

# **Statement of Basis**

**Tier I Operating Permit No. T1-2018.0033**

**Project ID 62082**

**Idaho Forest Group LLC - Chilco**

**Athol, Idaho**

**Facility ID 055-00024**

**Final**

**February 11, 2019**

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The purpose of this Statement of Basis is to set forth the legal and factual basis for the Tier I operating permit terms and conditions, including references to the applicable statutory or regulatory provisions for the terms and conditions, as required by IDAPA 58.01.01.362

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## 1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BMP	best management practices
Boiler MACT	40 CFR 63 Subpart DDDDD
Btu	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems as defined in 40 CFR 63.2
CO	carbon monoxide
CO <sub>2</sub>	carbon dioxide
CO <sub>2</sub> e	CO <sub>2</sub> equivalent emissions
COMS	continuous opacity monitoring systems
CPMS	Continuous parameter monitoring system, as defined in 40 CFR 63.2
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EFB	Electrified filter bed
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
IEU	insignificant emissions unit
IFG	Idaho Forest Group, LLC - Chilco Facility
iwg	inches of water gauge
km	kilometers
lb/hr	pounds per hour
m	meters
MACT	Maximum Achievable Control Technology
mg/dscm	milligrams per dry standard cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
MRRR	Monitoring, Recordkeeping and Reporting Requirements
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO <sub>2</sub>	nitrogen dioxide
NO <sub>x</sub>	nitrogen oxides
NPS	New Source Performance Standards
O&M	operation and maintenance

O <sub>2</sub>	oxygen
PC	permit condition
PCWP	Plywood and Composite Wood Products
PM	particulate matter
PM <sub>2.5</sub>	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM <sub>10</sub>	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTC	permit to construct
PTE	potential to emit
PW	process weight rate
RICE	reciprocating internal combustion engines
<i>Rules</i>	<i>Rules for the Control of Air Pollution in Idaho</i>
scf/hr	standard cubic feet per hour
SIP	State Implementation Plan
SO <sub>2</sub>	sulfur dioxide
SO <sub>x</sub>	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T1	Tier I operating permit
T2	Tier II operating permit
TAP	toxic air pollutants
T-RACT	Toxic Air Pollutant Reasonably Available Control Technology
ULSD	ultra low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compound

## 2. INTRODUCTION AND APPLICABILITY

Idaho Forest Group, LLC - Chilco Facility (IFG) is a manufacturer of dimensional lumber and located at 4447 East Chilco Road in Athol. The facility is classified as a major facility, as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), and volatile organic compounds (VOCs) above the major source threshold of 100 tons-per-year. The facility is also classified as a major facility, as defined by IDAPA 58.01.01.008.10.a, because it emits or has the potential to emit methanol and acetaldehyde above the major source thresholds of 10 tons-per-year for any single HAP and 25 tons-per-year for any combination of HAP.

As a major facility, IFG is required to apply for a Tier I operating permit pursuant to IDAPA 58.01.01.301. The application for a Tier I operating permit must contain a certification from IFG as to its compliance status with all applicable requirements (IDAPA 58.01.01.314.09).

IDAPA 58.01.01.362 requires that as part of its review of the Tier I application, DEQ shall prepare a technical memorandum (i.e., statement of basis) that sets forth the legal and factual basis for the draft Tier I operating permit terms and conditions including reference to the applicable statutory provisions or the draft denial. This document provides the basis for the draft Tier I operating permit for IFG.

The format of this Statement of Basis follows that of the permit with the exception of the facility's information discussed first followed by the scope, the applicable requirements and permit shield, and finally the general provisions.

IFG Tier I operating permit is organized into sections. They are as follows:

**Section 1 – Acronyms, Units, and Chemical Nomenclature**

Section 1 includes acronyms, units, and chemical nomenclature.

**Section 2 - Tier I Operating Permit Scope**

The scope describes this permitting action.

**Section 3 - Facility-Wide Conditions**

The Facility-wide Conditions section contains the applicable requirements (permit conditions) that apply facility-wide. Where required, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each permit condition follows the permit condition.

**Sections 4 through 9 - Emissions Units / Sources**

The emissions unit-specific sections of the permit contain the applicable requirements that specially apply to each regulated emissions unit. Some requirements that apply to an emissions unit (e.g., opacity limits) may be contained in the facility-wide conditions. As with the facility-wide conditions, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each applicable requirement immediately follows the applicable requirement.

**Section 10 - Insignificant Activities**

This section also lists emissions units and activities determined to be insignificant activities based on size or production as allowed by IDAPA 58.01.01.317.01.b.

**Section 11 - General Provisions**

The final section of the permit contains standard terms and conditions that apply to all major facilities subject to IDAPA 58.01.01.300. This section is the same for all Tier I sources. These conditions have been reviewed by EPA and contain all terms required by IDAPA 58.01.01 et al as well as requirements from other air quality laws and regulations. Each general provision has been paraphrased so it is more easily understood by the general public; however, there is no intent to alter the effect of the requirement. Should there be a discrepancy between a paraphrased general provision in this statement of basis and the rule or permit, the rule or permit shall govern.

### **3. FACILITY INFORMATION**

#### **3.1 Facility Description**

IFG produces dimensional lumber which is located at Athol, Idaho. The primary processes at the facility are the sawmill, steam plant (i.e., the boilers), drying lumber kilns, planer mill, and by-products handling.

Logs are stored in the log yard until they can be processed. Logs are debarked then cut to dimension in the sawmill. Bark from the debarker is hogged and pneumatically transferred to hog fuel storage or to the hog fuel boiler. Surplus bark is sold as a by-product. Green lumber is cut to length in the sawmill, dried in the facility's kilns, and planed in the planer mill. The finished lumber is packaged and shipped by truck or by railcar. By-products include bark, sawdust, sawmill chips, planer chips, and shavings.

#### **3.2 Facility Permitting History**

**Tier I Operating Permit History - Previous 5-year permit term April 4, 2014 to February 12, 2019**

The following information is the permitting history of the Tier I operating permit for this Tier I facility during the previous five-year permit term which was from April 4, 2014 to February 12, 2019. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

Permit Type	Permit Number	Issue Date	Project	Status
T1	T1-2012.0065 PROJ 61124	4/4/2014	Tier I renewal	A (will be S after the issuance of this permit)

**Underlying Permit History - Includes every underlying permit**

The following information is the comprehensive permitting history of all underlying applicable permits issued to this Tier I facility. This information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

Permit Type	Permit Number	Issue Date	Project	Status
PTC	P-030132	02/18/04	Transfer ownership from Louisiana-Pacific Corp to Chilco Lake Lumber Co. LLC	S
PTC	P-040100	08/20/04	For the construction of a hog fuel boiler with EFB, ash handling equip, EFB baghouse, NG boiler, kilns, planer mill, planer chipper, chip bin, shavings bin with cyclone and baghouse	S
PTC	P-050116	09/01/05	Increase CO emission, remove conditions on NG boiler, planer shaving baghouse, and planer chip target bin, add hog fuel cyclone	S
PTC	No. P-2013.0005 project 61153	5/10/2013	Decrease the annual CO emissions limit, remove all conditions related to the hog fuel cyclone, and put permit conditions related to the planer shavings baghouse and planer chip bin target box back into the permit.	S
PTC	No. P-2013.0005 project 61632	11/16/2016	PTC modification - Change the CO emission limit on the hog fuel fired boiler; change the VOC limit on the lumber drying kilns; add a 95 MMBtu/hr natural gas fired boiler to the steam plant; and replace the hog fuel fired boiler electrified filter bed (EFB) with an electrostatic precipitator (ESP).	A

**Underlying Documents – Consent Order, etc.**

IFG does not have active consent orders or settlement agreements at the time of issuing this permit.

## **4. APPLICATION SCOPE AND APPLICATION CHRONOLOGY**

### **4.1 Application Scope**

This permit is the renewal of the facility's currently effective Tier I operating permit. This permit includes the following changes to the existing permit:

- Incorporate the requirements in PTC No. P-2013.0005 PROJ 61632, issued November 16, 2016.
- Update the requirements in 40 CFR 63, Subpart DDDDD that apply to the hog fuel boiler because the subpart was amended on November 20, 2015, after the existing Tier I operating permit was issued in

2014 and because the control device of the boiler, electrified filter bed (EFB), was replaced with an electrostatic precipitator (ESP) in 2016.

- Update requirements in 40 CFR 63, Subpart DDDDD that apply to the new natural gas boiler that was installed in 2016.
- Remove requirements in 40 CFR 64 (CAM) for hog fuel boiler. According to the underlying PTC issued 11/16/2016, the hog fuel boiler complies with CAM requirements as long as the boiler complies with the boiler MACT (40 CFR 63 Subpart DDDDD).

## 4.2 Application Chronology

June 25, 2018	DEQ received an application.
August 20, 2018	DEQ determined that the application was complete.
October 9, 2018	DEQ made available the draft permit and statement of basis for peer and regional office review.
October 18, 2018	DEQ made available the draft permit and statement of basis for applicant review.
November 19 – December 19, 2018	DEQ provided a public comment period on the proposed action.
December 21, 2018	DEQ provided the proposed permit and statement of basis for EPA review.
February 11, 2019	DEQ issued the final permit and statement of basis.

## 5. EMISSIONS UNITS, PROCESS DESCRIPTION(S), AND EMISSIONS INVENTORY

This section lists the emissions units, describes the production or manufacturing processes, and provides the emissions inventory for this facility. The information presented was provided by the applicant in its permit application. Also listed in this section are the insignificant activities based on size or production rate.

### 5.1 Process No. 1 - HOG FUEL BOILER

Table 5.1 lists the emissions units and control devices associated with the hog fuel boiler.

**Table 5.1 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION**

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	<u>Hog fuel boiler</u> Manufacturer: Kipper and Sons, #1018 Date Manufactured: 1977 Rated heat capacity: 125 MMBtu/hr Rated steam capacity: 75,000 pounds steam per hour (permitted at 607,594 thousand pounds of steam per any consecutive 12-month period) Burner type: Spreader stoker Fuel: Woodwaste, 13 ton hog fuel/hr Stack flow rate: 43,000 acfm	<u>Multiclone</u> Manufacturer: Western Pneumatics, Inc. Efficiency: 95% for PM  <u>Electrostatic Precipitator (ESP)</u> Manufacturer: PPC Industries Plate cleaning system: rapping Secondary amperage: > 30 amperage/second Secondary voltage: > 15 voltage/second Spark rate: 0-100 per minute Design flow rate: 71,381 scfm Date installed: 2016	Hog fuel boiler stack

The hog fuel boiler provides steam to heat the facility's dry kilns and the facility's production buildings. The hog fuel boiler is rated at 75,000 pounds of steam per hour or 125 MMBtu/hr and is limited to 607,594 thousand pounds of steam per any consecutive 12-month period.

Emissions resulting from the combustion in the hog fuel boiler are first routed to a high efficiency multiclone. The multiclone is the primary PM emission control device. Ash and partially combusted wood fiber removed by the multiclone are then segregated by a classifier. From the classifier, partially combusted wood fiber is reintroduced back into the boiler firebox, and the ash is removed for disposal. After the multiclone, the uncaptured fine dust and smoke particles are collected in an electrostatic precipitator (ESP). The cleaned air stream from the ESP is vented through the boiler stack.

## 5.2 Process No. 2 - DRY KILNS (FOUR TOTAL)

Table 5.2 lists the emissions units and control devices associated with dry kilns.

**Table 5.2 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION**

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Four dry kilns	None	Vents

The dry kilns are used to dry green lumber. Lumber is dried by the steam produced by the facility's boilers. Vents on the dry kilns are opened and closed during batch drying cycles to control temperature and moisture within the kilns.

## 5.3 Process No. 3 - SAWMILL

Table 5.3 lists the emissions units and control devices associated with the sawmill.

**Table 5.3 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION**

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Sawmill chip bin target box	None	Target box
NA	Sawdust bin target box	None	Target box

Logs are debarked and cut into dimensional lumber in the sawmill. As a result of these processes, wood scraps and sawdust are produced. The wood scraps are chipped in a chipper. The fine size material is screened and added to sawdust that is pneumatically conveyed to the sawdust bin target box located on the outdoor sawdust bin. Chips are pneumatically transferred to a sawmill chip bin target box on the outdoor sawmill chip bin.

The sawdust building enclosure controls emissions from the sawing of logs and chipping of wood scrap.

## 5.4 Process No. 4 - FIRE-WATER PUMP ENGINE

Table 5.4 lists the emissions units and control devices associated with the fire-water pump engine.

**Table 5.4 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION**

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	<u>Fire-water pump engine</u> Manufacturer: Cummins Model: V-504-52 Date Manufactured: January 1983 Date installed: 2004 Rated capacity: 150 brake horsepower Fuel: diesel	None	Engine stack

The fire-water pump engine is a diesel-fired CI RICE with a site rating of 150 brake hp. It was installed in 2004. The fire-water pump engine is an emergency engine. It is only used for fire suppression. It is tested regularly to ensure readiness.



## 5.5 Process No. 5 - NATURAL GAS-FIRED BOILER

Table 5.5 lists the emissions units and control devices associated with the natural gas-fired boiler.

**Table 5.5 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION**

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	<u>Natural gas-fired boiler</u> Manufacturer: John Zink Hamsworth Rated Input Capacity: 95 MMBtu/hr Rated Steam Capacity: 80,000 lb/hr Date installed: 2016	None	Natural gas-fired boiler stack

The facility installed the natural gas-fired boiler in 2016. The steam from the boiler is for process use. Emissions from the natural gas-fired boiler are uncontrolled.

## 5.6 Process No. 6 - PLANER MILL

Table 5.6 lists the emissions units and control devices associated with the planer mill.

**Table 5.6 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION**

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Planer Shaving Cyclone	Fabric Filter Baghouse	Planer Shavings Cyclone Baghouse Vent
	Planer Chip Bin Target Box	None	Planer Chip Bin Target Box Vent

The planer and associated equipment reduce dried or green lumber to a desired width and thickness. Planer shavings generated by the process are transported pneumatically from the planer building to a cyclone on the shavings bin. The cyclone separates out the shavings from the air stream and drops them into the planer shavings bin. Planer chips generated by the process are pneumatically transported to a planer chip bin target box on the planer chip bin.

Emissions generated from the planer and associated equipment located inside the building are controlled by the building enclosure. Emissions resulting from the transport of planer shavings to the shavings bin are controlled by a baghouse on the planer shavings cyclone. Emissions resulting from the transport of planer chips to the planer chip bin target box are uncontrolled. Emissions from the planer shavings cyclone baghouse vent or the planer chip bin target box vent may be exhausted either back inside the building or outside the building.

## 5.7 Insignificant Emissions Units Based on Size or Production Rate

No emissions unit or activity subject to an applicable requirement may qualify as an insignificant emissions unit or activity. As required by IDAPA 58.01.01.317.01.b, insignificant emissions units (IEUs) based on size or production rate must be listed in the permit application. Table 5.7 lists the IEUs identified in the permit application. Also summarized is the regulatory authority or justification for each IEU.

**Table 5.7 INSIGNIFICANT EMISSION UNITS AND REGULATORY AUTHORITY/JUSTIFICATION**

Emissions Unit / Activity	Regulatory Authority / Justification
Bark Hog	IDAPA 58.01.01.317.01(b)(i)(30)
Covered Bark Conveyor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Screen (classifier), indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)

Emissions Unit / Activity	Regulatory Authority / Justification
Sawmill Chipper, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Hog Fuel Transfer to Fuel House	IDAPA 58.01.01.317.01(b)(i)(30)
Hog Fuel Truck Bin Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chipper and Screen	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Shavings Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)

## 5.8 Emissions Inventory (EI)

Table 5.8 summarizes the emissions inventory for this major facility. All values are expressed in units of tons-per-year and represent the facility's potential to emit. Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hour of operation or on the type or amount of material combusted, stored or processed shall be treated as part of its design if the limitation or the effect it would have on emission is state or federally enforceable.

The EI is taken from the underlying PTC No. P-2013.0005 project 61632 issued on November 16, 2016. (2016AAG1770[v4]). Refer to Appendix A for more details.

**Table 5.8 EMISSIONS INVENTORY - POTENTIAL TO EMIT (T/yr) <sup>1</sup>**

Sources	PM10 (ton/yr)	PM2.5 (ton/yr)	SO2 (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	HAPS (ton/yr)
<b>Lumber Drying</b>							
LUMBER DRY KILNS	6.18	5.36	---	---	238.5	---	23.8
<b>Sawmill Point Sources</b>							
SAWMILL CHIP BIN VENT - POINT SOURCE	6.27	1.88	---	---	---	---	---
SAWDUST BIN VENT - POINT SOURCE	2.65	0.80	---	---	---	---	---
<b>Planer Point Sources</b>							
PLANER CHIPPER TARGET BOX - POINT SOURCE	0.40	0.12	---	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE	5.44	1.63	---	---	---	---	---
<b>Steam Plant</b>							
KIPPER & SONS HOG FUEL BOILER	30.4	30.4	12.66	111.39	8.6	249.4	20.2
NEW NATURAL GAS BOILER	0.22	0.18	0.25	26.05	2.28	15.86	0.78
<b>Proposed Point Source Totals (tpy)</b>	<b>51.55</b>	<b>40.37</b>	<b>12.91</b>	<b>137.45</b>	<b>249</b>	<b>265</b>	<b>44.8</b>

## 6. EMISSIONS LIMITS AND MRRR

This section contains the applicable requirements for this major facility. Where applicable, monitoring, recordkeeping and reporting requirements (MRRR) follow the applicable requirement and state how compliance with the applicable requirement is to be demonstrated.

This section is divided into several subsections. The first subsection lists the requirements that apply facility wide. The next subsection lists the emissions units- and emissions activities-specific applicable requirements. The final subsection contains the general provisions that apply to all major facilities subject to Idaho DEQ's Tier I operating permit requirements.

This section contains the following subsections:

- Facility-Wide Conditions;
- Emissions Unit No. 1 Hog Fuel Boiler;
- Emissions Unit No. 2 Dry Kilns;
- Emissions Unit No. 3 Sawmill;

- Emissions Unit No. 4 Fire-Water Pump Engine;
- Emissions Unit No. 5 Natural gas-fired boiler;
- Emissions Unit No. 6 Planer mill; and
- Tier I Operating Permit General Provisions.

### ***MRRR***

Monitoring, recordkeeping and reporting requirements (MRRR) are the means with which compliance with an applicable requirement is demonstrated. In this section, the applicable requirement (permit condition) is provided first followed by the MRRR. Should an applicable requirement not include sufficient MRRR to satisfy IDAPA 58.01.01.322.06, 07, and 08, then the permit must establish adequate monitoring, recordkeeping and reporting sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit (i.e. gap filling). In addition to the specific MRRR provided for each applicable requirement, generally applicable facility-wide conditions and general provisions may also be provided, such as performance testing, reporting, and certification requirements.

The legal and factual basis for each permit condition is provided for in this document. If a permit condition was changed due to facility draft comments or public comments, an explanation of the changes is provided.

### ***State Enforceability***

An applicable requirement that is not required by the federal CAA and has not been approved by EPA as a SIP-approved requirement is identified as a "State-only" requirement and is enforceable only under state law. State-only requirements are not enforceable by the EPA or citizens under the CAA. State-only requirements are identified in the permit within the citation of the legal authority for the permit condition.

### ***Federal Enforceability***

Unless identified as "State-only," all applicable requirements, including MRRR, are state and federally enforceable. It should be noted that while a violation of a MRRR is a violation of the permit, it is not necessarily a violation of the underlying applicable requirement (e.g. emissions limit).

To minimize the length of this document, the following permit conditions and MRRR have been paraphrased. Refer to the permit for the complete requirements.

## **6.1 Facility-Wide Conditions**

Facility-Wide Condition section is updated to follow the current Tier I operating permit template. Table 3.1 in the permit is also updated.

### **Permit Condition 3.1 - Fugitive Dust**

All reasonable precautions shall be taken to prevent PM from becoming airborne in accordance with IDAPA 58.01.01.650-651.

[IDAPA 58.01.01.650-651, 3/30/07]

### **MRRR (Permit Conditions 3.2 through 3.4)**

- Monitor and maintain records of the frequency and the methods used to control fugitive dust emissions;
- Maintain records of all fugitive dust complaints received and the corrective action taken in response to the complaint; and
- Conduct facility-wide inspections of all sources of fugitive emissions. If any of the sources of fugitive dust are not being reasonably controlled, corrective action is required.

[IDAPA 58.01.01.322.06, 07, 08, 4/5/2000]

**Permit Condition 3.5 - Odors**

The permittee shall not allow, suffer, cause, or permit the emission of odorous gases, liquids, or solids to the atmosphere in such quantities as to cause air pollution.

[IDAPA 58.01.01.775-776 (State-only), 5/1/94]

**MRRR (Permit Condition 3.6)**

- Maintain records of all odor complaints received and the corrective action taken in response to the complaint.
- Take appropriate corrective action if the complaint has merit, and log the date and corrective action taken.

[IDAPA 58.01.01.322.06, 07 (State only), 5/1/94]

**Permit Condition 3.7 - Visible Emissions**

The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined by procedures contained in IDAPA 58.01.01.625. These provisions shall not apply when the presence of uncombined water, nitrogen oxides, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this section.

[IDAPA 58.01.01.625, 4/5/00]

**MRRR (Permit Condition 3.8 through 3.9)**

- Conduct facility-wide inspections of all emissions units subject to the visible emissions standards (or rely on continuous opacity monitoring);
- If visible emissions are observed, take appropriate corrective action and/or perform a Method 9 opacity test; and
- Maintain records of the results of each visible emissions inspection.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

**Permit Conditions 3.10 through 3.14 - Excess Emissions**

The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions. The provisions of IDAPA 58.01.01.130-136 shall govern in the event of conflicts between the excess emissions facility wide conditions and the regulations of IDAPA 58.01.01.130-136.

**MRRR (Permit Conditions 3.11 through 3.14)**

Monitoring, recordkeeping and reporting requirements for excess emissions are provided in Sections 131 through 136.

- Take appropriate action to correct, reduce, and minimize emissions from excess emissions events;
- Prohibit excess emissions during any DEQ Atmospheric Stagnation Advisory or Wood Stove Curtailment Advisory; and
- Notify DEQ of each excess emissions events as soon as possible, including information regarding upset, breakdown, or safety events.
- Submit a report for each excess emissions event to DEQ.
- Maintain records of each excess emissions event.

### **Permit Condition 3.15 – Fuel-Burning Equipment PM Standards**

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas, 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid, 0.050 gr/dscf of effluent gas corrected to 8% oxygen by volume for coal, and 0.080 gr/dscf of effluent gas corrected to 8% oxygen by volume for wood products.  
[IDAPA 58.01.01.676-677, 5/1/94]

#### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Condition 3.16 - Sulfur Content Limits**

The permittee shall not sell, distribute, use, or make available for use any of the following:

- Distillate fuel oil containing more than the following percentages of sulfur:
  - ASTM Grade 1 fuel oil, 0.3% by weight.
  - ASTM Grade 2 fuel oil, 0.5% by weight.
- Coal containing greater than 1.0% sulfur by weight.
- DEQ may approve an exemption from these fuel sulfur content requirements (IDAPA 58.01.01.725.01 725.04) if the permittee demonstrates that, through control measures or other means, SO<sub>2</sub> emissions are equal to or less than those resulting from the combustion of fuels complying with these limitations.

[IDAPA 58.01.01.725, 3/29/10]

#### **MRRR - (Permit Condition 3.17)**

The permittee shall maintain documentation of supplier verification of fuel sulfur content on an as received basis.

[IDAPA 58.01.01.322.06, 5/1/94]

### **Permit Condition 3.18 - Open Burning**

The permittee shall comply with the *Rules for Control of Open Burning*, IDAPA 58.01.01.600-623.

[IDAPA 58.01.01.600-623, 5/08/09]

#### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Condition 3.19 - Asbestos**

The permittee shall comply with all applicable requirements of 40 CFR 61, Subpart M—“National Emission Standard for Asbestos.”

[40 CFR 61, Subpart M]

#### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Condition 3.20 - Accidental Release Prevention**

An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance present above a threshold quantity is first listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process.  
[40 CFR 68.10 (a); 40 CFR 68.215(a)(2); IDAPA 58.01.01.322.11, 4/6/05; 40 CFR 68.215(a)(ii)]

#### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Condition 3.21 - Recycling and Emissions Reductions**

The permittee shall comply with applicable standards for recycling and emissions reduction of refrigerants and their substitutes pursuant to 40 CFR 82, Subpart F, Recycling and Emissions Reduction.  
[40 CFR 82, Subpart F]

#### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Condition 3.22 through 3.23- NSPS/NESHAP General Provisions**

This facility is subject to NSPS Subpart Dc and NESHAP Subparts DDDD, ZZZZ, and DDDDD and is therefore required to comply with applicable General Provisions.

[40 CFR 60/63, Subpart A]

#### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Condition 3.24 - Monitoring and Recordkeeping**

The permittee shall maintain sufficient records to assure compliance with all of the terms and conditions of this operating permit. Records of monitoring information shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

#### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Conditions 3.25 through 3.28 - Performance Testing**

If performance testing is required, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test or shorter time period as provided in a permit, order, consent decree, or by DEQ approval. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests such testing not be performed on weekends or state holidays.

All testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, prior to conducting any performance test, the permittee is encouraged to submit in writing to DEQ, at least 30 days in advance, the following for approval:

- The type of method to be used;
- Any extenuating or unusual circumstances regarding the proposed test; and
- The proposed schedule for conducting and reporting the test.

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

### **MRRR (Permit Conditions 3.26 and 3.28)**

The permittee shall submit compliance test report(s) to DEQ following testing.

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

### **Permit Condition 3.29 - Reports and Certifications**

This permit condition establishes generally applicable MRRR for submittal of reports, certifications, and notifications to DEQ and/or EPA as specified.

[IDAPA 58.01.01.322.08, 11, 5/1/94]

### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

### **Permit Condition 3.30 - Incorporation of Federal Requirements by Reference**

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein.

[IDAPA 58.01.01.107, 4/7/11]

### **MRRR**

No specific monitoring is required for this facility-wide condition. As with all permit conditions, the permittee must certify compliance with this condition annually, which includes making a reasonable inquiry to determine if this requirement was met during the reporting period.

## **6.2 Emissions Unit-Specific Emissions Limits and MRRR**

### **HOG FUEL-FIRED BOILER**

For additional discussions on the emissions limits and MRRR, refer to the SOB for the underlying PTC No. P-2013.0005 project 61632 issued on November 16, 2016. (2016AAG1770[v4])

For Boiler MACT :

Table 4.5 of the permit is revised because the boiler does not use continuous oxygen trim system according to the boiler MACT federal regulation review provided in the application and because the boiler MACT was amended in 2015.

Table 4.6 is revised to reflect that the boiler is now using ESP instead of EFB and includes the Boiler MACT 2015 amendment.

Other changes are due to the 2015 boiler MACT amendments.

According to DEQ regional office inspector on October 15, 2018, initial requirements have been fulfilled.

#### **Permit Condition 4.1**

Emissions limits in PC 4.1 for the hog fuel-fired boiler stack are taken from the PTC issued on 11/16/2016. It is an applicable requirement according to IDAPA 58.01.01.008.03.

#### **MRRR - (Permit Conditions 4.5, 4.6, 4.7, 4.8, 4.9, 4.10, 3.25-3.28)**

Demonstrating compliance with PC 4.1 is specified in the underlying PTC issued on 11/16/2016. The following summarizes the methods used to demonstrate compliance:

PM<sub>2.5</sub>/PM<sub>10</sub>

- Require to use multiclone and ESP to control emissions from the hog fuel boiler (PC 4.6);
- Limit steam production rate of the hog fuel boiler not to exceed 607,594 thousand pounds of steam per any consecutive 12-month period (PC 4.5);
- Conduct performance test (PC 4.9) and report the testing results (PCs 3.25 to 3.28); and
- Monitor steam production rate (PC 4.10).

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- Limit steam production rate of the hog fuel boiler not to exceed 607,594 thousand pounds of steam per any consecutive 12-month period (PC 4.5);
- Conduct performance test (PC 4.8) and report the testing results (PCs 3.25 to 3.28); and
- Monitor steam production rate (PC 4.10) .

NOx

- Conduct performance test (PC 4.7) and report the testing results (PCs 3.25 to 3.28).

#### **Permit Condition 4.2**

The formaldehyde emissions limit for the hog fuel-fired boiler stack in the PTC issued on November 16, 2016, is not included in the Tier I operating permit. The limit was originally developed according to IDAPA 58.01.01.210 before the boiler MACT became effective. The permit condition is an obsolete permit condition according to DEQ's interpretation of the toxic rules under IDAPA 58.01.01.210. The interpretation reads: *It is presumed that EPA evaluated the 187 HAPs when developing the emission standards for new, modified or existing stationary sources regulated by 40 CFR Part 63; therefore, no further review is required under IDAPA 58.01.01.210 for these pollutants for sources subject to 40 CFR Part 63, including sources specifically exempted within the subpart.*

#### **Permit Condition 4.3**

The PM (grain loading standard) emissions limit in PC 4.3 for the hog fuel-fired boiler stack is taken from the PTC issued on 11/16/2016. It is an applicable requirement according to IDAPA 58.01.01.008.03.

#### **MRRR - (Permit Condition 4.6)**

Demonstrating compliance with PC 4.3 is specified in the underlying PTC issued on November 16, 2016. The following summarizes the methods used to demonstrate compliance:

- Require to use multiclone and ESP to control emissions from the hog fuel boiler (PC 4.6)

#### **Permit Condition 4.13**

Emission limitations, work practice standards, and operating limits in PC 4.13 for the hog fuel-fired boiler stack are taken from 40 CFR 63 Subpart DDDDD (boiler MACT). They are applicable requirements according to IDAPA 58.01.01.008.03.



**MRRR - (Permit Conditions 4.15 - 4.74)**

Demonstrating compliance with PC 4.13 is specified in the boiler MACT. Refer to the permit and the federal regulation review for the boiler MACT in Appendix C.3 of the SOB.

**DRY KILNS (4 TOTAL)****Permit Condition 5.1**

PM<sub>10</sub> and VOC emissions limits for the dry kilns vents are taken from the PTC issued on November 16, 2016. They are applicable requirements according to IDAPA 58.01.01.008.03.

**MRRR - (Permit Conditions 5.3, 5.4, 5.5, 3.24)**

Demonstrating compliance with PC 5.1 is specified in the underlying PTC issued on November 16, 2016. The following summarizes the methods used to demonstrate compliance:

- Limit annual lumber throughput (PC 5.3)
- Monitor and record lumber throughput rate monthly and annually (PC 5.4) and in accordance with PC 3.24.
- Calculate VOC emissions (PC 5.5)

**Permit Condition 5.2**

Permit Condition 5.2 regarding visible emissions limit for the dry kilns vents is taken from the PTC issued on November 16, 2016. It is an applicable requirement according to IDAPA 58.01.01.008.03.

**MRRR - (Permit Conditions 3.7 to 3.9)**

Demonstrating compliance with PC 5.4 was specified in the underlying PTC issued on November 16, 2016. The following summarizes the methods used to demonstrate compliance:

- Monthly facility-wide see/no see inspection (PCs 3.7 through 3.9)

**SAWMILL****Permit Conditions 6.1 and 6.2**

Permit Conditions 6.1 and 6.2 regarding PM<sub>10</sub> emissions limits for the sawmill chip bin target box vent and the sawdust bin target box vent are taken from the PTC issued on November 16, 2016. They are applicable requirements according to IDAPA 58.01.01.008.03.

**MRRR - (Permit Conditions 6.4, 6.5, 3.24)**

Demonstrating compliance with PCs 6.1 and 6.2 was specified in the underlying PTC issued on November 16, 2016. The following summarizes the methods used to demonstrate compliance:

- Limit annual throughputs of the sawmill chip bin and the sawdust bin. (PC 6.4)
- Monitor and record throughput rate monthly and annually (PC 6.5) and in accordance with PC 3.24.

**Permit Condition 6.3**

PC 6.3 regarding visible emissions limit for sawmill is taken from the underlying PTC issued on November 16, 2016. It is an applicable requirement according to IDAPA 58.01.01.008.03.

**MRRR - (Permit Condition 6.6)**

Demonstrating compliance with PC 6.3 was specified in the underlying PTC issued on November 16, 2016. The following summarizes the methods used to demonstrate compliance:

- Monthly facility-wide see/no see inspection (PC 6.6)

## **FIRE-WATER PUMP ENGINE**

The engine is subject to requirements in 40 CFR 63, Subpart ZZZZ. Detailed discussions can be found under Regulatory Review section and Appendix C.2 of this document. The requirements in 40 CFR 63, Subpart ZZZZ are applicable requirements according to IDAPA 58.01.01.008.03.

### **Permit Condition 7.3**

Emissions and operating limitations in PC 7.3 are taken from 40 CFR 63, Subpart ZZZZ.

### **MRRR - (Permit Conditions 7.2, 7.4 to 7.8)**

MRRR are taken from 40 CFR 63, Subpart ZZZZ. They are summarized as follows:

- Compliance date (PC 7.2);
- General compliance requirements (PC 7.4);
- Operation and monitoring requirements (PC 7.5);
- Continuous compliance requirements (PC 7.6);
- Recordkeeping requirements (PC 7.7); and
- Requirements in 40 CFR 63, Subpart A (PC 7.8).

## **NATURAL GAS-FIRED BOILER**

For additional discussions on the emissions limits and MRRR, refer to the SOB for the underlying PTC No. P-2013.0005 project 61632 issued on November 16, 2016. (2016AAG1770[v4])

For Boiler MACT :

Table 8.4 is revised because the natural gas boiler does not use continuous oxygen trim system according to the boiler MACT federal regulation analysis provided in the application.

Table 8.5 is revised according to the boiler MACT federal regulation analysis provided in the application.

Other changes are due to the 2015 boiler MACT amendments.

### **Permit Condition 8.1**

Permit Condition 8.1 regarding NO<sub>x</sub> emissions limit for the natural gas boiler is taken from the underlying PTC issued on November 16, 2016. They are applicable requirements according to IDAPA 58.01.01.008.03.

### **MRRR - (Permit Condition 8.2)**

Demonstrating compliance with PC 8.1 is specified in the underlying PTC issued on November 16, 2016. The following summarizes the method used to demonstrate compliance:

- NO<sub>x</sub> source testing (PC 8.2)

### **Permit Conditions 8.3 and 8.4 (NSPS)**

The natural gas-fired boiler is subject to the requirements in 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. They are applicable requirements in according to IDAPA 58.01.01.008.03.

The permittee is subject to reporting and recordkeeping requirements in 40 CFR 60, Subpart Dc (PC 8.4).

### **MRRR**

No other MRRR are required in 40 CFR 60, Subpart Dc for the natural gas-fired boiler. The regulatory review of the subpart can be found in Appendix C.1 of the SOB.

### Permit Conditions 8.5 to 8.25 (Boiler MACT)

The natural gas-fired boiler is subject to 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. The boiler is subject to work practice standards in the subpart (PC 8.7). The MRRR is specified in the subpart. The table of content of the subpart clearly outlines the MRRR. Detailed regulatory analysis, including the table of content of the subpart, can be found in Appendix C.3 of this document.

### PLANER MILL

#### Permit Condition 9.1

As discussed in the PTC, issued on November 16, 2016, the PM<sub>10</sub> emissions limits in PC 9.1 only apply when emissions from the planer shavings cyclone baghouse and the planer chip bin target box are exhausted outside the building; when emissions from these two vents are exhausted inside the building the emissions limits do not apply. The limits are applicable requirements in according to IDAPA 58.01.01.008.03.

#### MRRR - (Permit Conditions 9.3 to 9.9)

Demonstrating compliance with the limits in PC 9.1 was specified in the underlying PTC issued on 11/16/2016. The following summarizes the methods used to demonstrate compliance:

- Install and operate the planer shavings bin baghouse in accordance with manufacturer recommendations. (PCs 9.3 and 9.4)
- Limit annual throughputs of the planer chip bin and the planer shavings bin. (PCs 9.5 and 9.6)
- Monitor and record throughput rates monthly and annually. (PCs 9.7 and 9.8)
- Monitor and record pressure drop across the planer shavings baghouse weekly. (PC 9.9)

#### Permit Condition 9.2

Permit Condition 9.2 is visible emissions limit taken from the PTC issued on November 16, 2016. They are applicable requirements in according to IDAPA 58.01.01.008.03.

#### MRRR – (Permit Condition 9.10)

Demonstrating compliance with PC 9.2 was specified in the underlying PTC issued November 16, 2016.

- Monthly facility-wide see/no see inspection (PC 9.10)

### INSIGNIFICANT ACTIVITIES

The following insignificant activities list is provided in the application and is the same as the one in the existing Tier I operating permit.

Description	Insignificant Activities IDAPA 58.01.01.317.01(b)(i) Citation
Bark Hog	IDAPA 58.01.01.317.01(b)(i)(30)
Covered Bark Conveyor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Screen (classifier), indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Chipper, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Hog Fuel Transfer to Fuel House	IDAPA 58.01.01.317.01(b)(i)(30)

Description	Insignificant Activities
	IDAPA 58.01.01.317.01(b)(i) Citation
Hog Fuel Truck Bin Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chipper and Screen	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Shavings Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)

### 6.3 General Provisions

Unless expressly stated, there are no MRRR for the general provisions.

#### General Compliance, Duty to Comply

The permittee must comply with the terms and conditions of the permit.

[IDAPA 58.01.01.322.15.a, 5/1/94; 40 CFR 70.6(a)(6)(i)]

#### General Compliance, Need to Halt or Reduce Activity Not a Defense

The permittee cannot use the fact that it would have been necessary to halt or reduce an activity as a defense in an enforcement action.

[IDAPA 58.01.01.322.15.b, 5/1/94; 40 CFR 70.6(a)(6)(ii)]

#### General Compliance, Duty to Supplement or Correct Application

The permittee must promptly submit such supplementary facts or corrected information upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application. The permittee must also provide information as necessary to address any new requirements that become applicable after the date a complete application has been filed but prior to the release of a draft permit.

[IDAPA 58.01.01.315.01, 5/1/94; 40 CFR 70.5(b)]

#### Reopening, Additional Requirements, Material Mistakes, Etc.

This term lists the instances when the permit must be reopened and revised, including times when additional requirements become applicable, when the permit contains mistakes, or when revision or revocation is necessary to assure compliance with applicable requirements.

[IDAPA 58.01.01.322.15.c, 5/1/94; IDAPA 58.01.01.386, 3/19/99; 40 CFR 70.7(f)(1), (2); 40 CFR 70.6(a)(6)(iii)]

#### Reopening, Permitting Actions

This term discusses modification, revocation, reopening, and/or reissuance of the permit for cause. If the permittee files a request to modify, revoke, reissue, or terminate the permit, the request does not stay any permit condition, nor does notification of planned changes or anticipated noncompliance.

[IDAPA 58.01.01.322.15.d, 5/1/94; 40 CFR 70.6(a)(6)(iii)]

#### Property Rights

This permit does not convey any property rights of any sort, or any exclusive privilege.

[IDAPA 58.01.01.322.15.e, 5/1/94; 40 CFR 70.6(a)(6)(iv)]

#### Information Requests

The permittee must furnish, within a reasonable time to DEQ, any information, including records required by the permit, that is requested in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit.

[Idaho Code §39-108; IDAPA 58.01.01.122, 4/5/00; IDAPA 58.01.01.322.15.f, 4/5/00; 40 CFR 70.6(a)(6)(v)]

### **Information Requests, Confidential Business Information**

Upon request, the permittee must furnish to DEQ copies of records required to be kept by this permit. For information claimed to be confidential, the permittee may furnish such records along with a claim of confidentiality in accordance with Idaho Code §9-342A and applicable implementing regulations including IDAPA 58.01.01.128.

[IDAPA 58.01.01.322.15.g, 5/1/94; IDAPA 58.01.01.128, 4/5/00; 40 CFR 70.6(a)(6)(v)]

### **Severability**

If any provision of the permit is held to be invalid, all unaffected provisions of the permit will remain in effect and enforceable.

[IDAPA 58.01.01.322.15.h, 5/1/94; 40 CFR 70.6(a)(5)]

### **Changes Requiring Permit Revision or Notice**

The permittee may not commence construction or modification of any stationary source, facility, major facility, or major modification without first obtaining all necessary permits to construct or an approval under IDAPA 58.01.01.213, or complying with IDAPA 58.01.01.220 through 223. The permittee must comply with IDAPA 58.01.01.380 through 386 as applicable.

[IDAPA 58.01.01.200-223, 4/2/08; IDAPA 58.01.01.322.15.i, 3/19/99; IDAPA 58.01.01.380-386, 7/1/02; 40 CFR 70.4(b)(12), (14), (15), and 70.7(d), (e)]

Changes that are not addressed or prohibited by the Tier I operating permit require a Tier I operating permit revision if such changes are subject to any requirement under Title IV of the CAA, 42 U.S.C. Section 7651 through 7651c, or are modifications under Title I of the CAA, 42 U.S.C. Section 7401 through 7515. Administrative amendments (IDAPA 58.01.01.381), minor permit modifications (IDAPA 58.01.01.383), and significant permit modifications (IDAPA 58.01.01.382) require a revision to the Tier I operating permit. IDAPA 58.01.01.502(b)(10) changes are authorized in accordance with IDAPA 58.01.01.384. Off permit changes and required notice are authorized in accordance with IDAPA 58.01.01.385.

[IDAPA 58.01.01.381-385, 7/1/02; IDAPA 58.01.01.209.05, 4/11/06; 40 CFR 70.4(b)(14) and (15)]

### **Federal and State Enforceability**

All permit conditions are federally enforceable unless specified in the permit as a state or local only requirement. State and local only requirements are not required under the CAA and are not enforceable by EPA or by citizens.

[IDAPA 58.01.01.322.15.j, 5/1/94; IDAPA 58.01.01.322.15.k, 3/23/98; Idaho Code §39-108; 40 CFR 70.6(b)(1), (2)]

### **Inspection and Entry**

Upon presentation of credentials, the facility shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where a Tier I source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108; IDAPA 58.01.01.322.15.l, 5/1/94; 40 CFR 70.6(c)(2)]

### **New Applicable Requirements**

The permittee must continue to comply with all applicable requirements and must comply with new requirements on a timely basis.

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.10.a.ii, 5/1/94; 40 CFR 70.6(c)(3) citing 70.5(c)(8)]

### **Fees**

The owner or operator of a Tier I source shall pay annual registration fees to DEQ in accordance with IDAPA 58.01.01.387 through IDAPA 58.01.01.397.

[IDAPA 58.01.01.387, 4/2/03; 40 CFR 70.6(a)(7)]

### **Certification**

All documents submitted to DEQ shall be certified in accordance with IDAPA 58.01.01.123 and comply with IDAPA 58.01.01.124.

[IDAPA 58.01.01.322.15.o, 5/1/94; 40 CFR 70.6(a)(3)(iii)(A); 40 CFR 70.5(d)]

### **Renewal**

The permittee shall submit an application to DEQ for a renewal of this permit at least six months before, but no earlier than 18 months before, the expiration date of this operating permit. To ensure that the term of the operating permit does not expire before the permit is renewed, the owner or operator is encouraged to submit a renewal application nine months prior to the date of expiration.

[IDAPA 58.01.01.313.03, 4/5/00; 40 CFR 70.5(a)(1)(iii)]

If a timely and complete application for a Tier I operating permit renewal is submitted, but DEQ fails to issue or deny the renewal permit before the end of the term of this permit, then all the terms and conditions of this permit including any permit shield that may have been granted pursuant to IDAPA 58.01.01.325 shall remain in effect until the renewal permit has been issued or denied.

[IDAPA 58.01.01.322.15.p, 5/1/94; 40 CFR 70.7(b)]

### **Permit Shield**

Compliance with the terms and conditions of the Tier I operating permit, including those applicable to all alternative operating scenarios and trading scenarios, shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

- Such applicable requirements are included and are specifically identified in the Tier I operating permit; or
  - DEQ has determined that other requirements specifically identified are not applicable and all of the criteria set forth in IDAPA 58.01.01.325.01(b) have been met.
- The permit shield shall apply to permit revisions made in accordance with IDAPA 58.01.01.381.04 (administrative amendments incorporating the terms of a permit to construct), IDAPA 58.01.01.382.04 (significant modifications), and IDAPA 58.01.01.384.03 (trading under an emissions cap).
- Nothing in this permit shall alter or affect the following:
  - Any administrative authority or judicial remedy available to prevent or terminate emergencies or imminent and substantial dangers;
  - The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;
  - The applicable requirements of the acid rain program, consistent with 42 U.S.C. Section 7651(g)(a); and

- The ability of EPA to obtain information from a source pursuant to Section 114 of the CAA; or the ability of DEQ to obtain information from a source pursuant to Idaho Code §39-108 and IDAPA 58.01.01.122.

[Idaho Code §39-108 and 112; IDAPA 58.01.01.122, 4/5/00;  
IDAPA 58.01.01.322.15.m, 325.01, 5/1/94; IDAPA 58.01.01.325.02, 3/19/99;  
IDAPA 58.01.01.381.04, 382.04, 383.05, 384.03, 385.03, 3/19/99; 40 CFR 70.6(f)]

### **Compliance Schedule and Progress Reports**

- For each applicable requirement for which the source is not in compliance, the permittee shall comply with the compliance schedule incorporated in this permit.
- For each applicable requirement that will become effective during the term of this permit and that provides a detailed compliance schedule, the permittee shall comply with such requirements in accordance with the detailed schedule.
- For each applicable requirement that will become effective during the term of this permit that does not contain a more detailed schedule, the permittee shall meet such requirements on a timely basis.
- For each applicable requirement with which the permittee is in compliance, the permittee shall continue to comply with such requirements.

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.9, 5/1/94; IDAPA 58.01.01.314.10, 4/5/00;  
40 CFR 70.6(c)(3) and (4)]

### **Periodic Compliance Certification**

The permittee shall submit compliance certifications during the term of the permit for each emissions unit to DEQ and the EPA as specified.

- Compliance certifications for all emissions units shall be submitted annually unless otherwise specified;
- All original compliance certifications shall be submitted to DEQ and a copy of all compliance certifications shall be submitted to the EPA.

[IDAPA 58.01.01.322.11, 4/6/05; 40 CFR 70.6(c)(5)(iii) as amended,  
62 Fed. Reg. 54900, 54946 (10/22/97); 40 CFR 70.6(c)(5)(iv)]

### **False Statements**

The permittee may not make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

### **No Tampering**

The permittee may not render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

### **Semiannual Monitoring Reports.**

In addition to all applicable reporting requirements identified in this permit, the permittee shall submit reports of any required monitoring at least every six months as specified.

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.322.08.c, 4/5/00; 40 CFR 70.6(a)(3)(iii)]

### **Reporting Deviations and Excess Emissions**

Each and every applicable requirement, including MRRR, is subject to prompt deviation reporting. Deviations due to excess emissions must be reported in accordance Sections 130-136. All instances of deviation from Tier I operating permit requirements must be included in the deviation reports. The reports must describe the probable cause of the deviation and any corrective action or preventative measures taken. Deviation reports must be submitted at least every six months unless the permit specifies a

different time period as required by IDAPA 58.01.01.322.08.c. Examples of deviations include, but are not limited to, the following:

- Any situation in which an emissions unit fails to meet a permit term or condition;
- Emission control device does not meet a required operating condition;
- Observations or collected data that demonstrate noncompliance with an emissions standard; and
- Failure to comply with a permit term that requires a report.

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.135, 4/11/06; 40 CFR 70.6(a)(3)(iii)]

#### **Permit Revision Not Required, Emissions Trading**

No permit revision will be required, under any approved, economic incentives, marketable permits, emissions trading, and other similar programs or processes, for changes that are provided for in the permit.

[IDAPA 58.01.01.322.05.b, 4/5/00; 40 CFR 70.6(a)(8)]

#### **Emergency**

In accordance with IDAPA 58.01.01.332, an “emergency” as defined in IDAPA 58.01.01.008, constitutes an affirmative defense to an action brought for noncompliance with such technology-based emissions limitation if the conditions of IDAPA 58.01.01.332.02 are met.

[IDAPA 58.01.01.332.01, 4/5/00; 40 CFR 70.6(g)]

## **7. REGULATORY REVIEW**

### **7.1 Attainment Designation (40 CFR 81.313)**

The facility is located in Kootenai County which is designated as attainment or unclassifiable for PM<sub>10</sub>, PM<sub>2.5</sub>, CO, NO<sub>2</sub>, SO<sub>x</sub>, and Ozone. Reference 40 CFR 81.313.

### **7.2 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)**

The facility is classified as a major facility for Title V program, as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit NO<sub>x</sub>, CO, and VOCs above the major source threshold of 100 tons-per-year. The facility is also classified as a major facility, as defined by IDAPA 58.01.01.008.10.a, because it emits or has the potential to emit methanol and acetaldehyde above the major source thresholds of 10 tons-per-year for any single HAP and 25 tons-per-year for any combination of HAP.

### **7.3 PSD Classification (40 CFR 52.21)**

The facility is classified as an existing major stationary source, because the estimated emissions of CO (i.e., 265 T/yr) have the potential to exceed major stationary source thresholds. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a).

### **7.4 NSPS Applicability (40 CFR 60)**

40 CFR 60, Subpart Dc .....Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

The natural gas-fired boiler is subject to 40 CFR 60, Subpart Dc. The regulatory analysis, submitted by the applicant and reviewed by DEQ staff, can be found in Appendix C.1 of this document.

#### Non-applicability

40 CFR 60, Subpart IIII.....Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

The fire-water pump engine is not subject to this subpart because it was installed in 2004, prior to the model years listed in the regulation.



40 CFR 60, Subpart Db.....Standards for Industrial-Commercial-Institutional Steam  
Generating Units.

As discussed in the statement of basis for the the initial Tier I issued on May 2, 2008, the hog-fuel fired boiler is not subject to this subpart as discussed as follows:

“The hog fuel boiler was originally built in 1977 and has not been modified or reconstructed, per NSPS definitions, since June 19, 1984, which is the trigger date for the NSPS Subpart Db. In accordance with this information, the hog fuel boiler is not subject to NSPS requirements of Subpart Db.”

**7.5 NESHAP Applicability (40 CFR 61)**

The facility is not subject to any requirements in 40 CFR 61.

**7.6 MACT Applicability (40 CFR 63)**

40 CFR 63, Subpart DDDD..... Plywood and Composite Wood Products (PCWP)

As discussed in the statement of basis for the the initial Tier I issued on May 2, 2008, the dry kilns are subject to this subpart:

“This subpart applies to lumber kilns at any facility that is major source of HAPs, so it applies to this facility. For kilns, only the initial notification requirements in Section 63.9(b) apply. On January 29, 2005, the facility notified EPA of applicability of subpart PCWP. Because the required notification has been made, no permit requirement will be written in this permit for the kilns.”

40 CFR 63, Subpart ZZZZ.....National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The fire-water pump engine is subject to this subpart. The regulatory analysis, submitted by the applicant and reviewed by DEQ staff, can be found in Appendix C.2 of this document.

40 CFR 63, Subpart DDDDD..... National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

The hog fuel boiler and natural gas-fired boiler are subject to this subpart. The regulatory analysis, submitted by the applicant and reviewed by DEQ staff, can be found in Appendix C.3 of this document.

**7.7 CAM Applicability (40 CFR 64)**

In accordance with 40 CFR 64.2(b), the hog fuel boiler is exempt from the CAM requirements for the filterable PM because the hog fuel boiler is subject to a filterable PM limit in 40 CFR 63, Subpart DDDDD.

Other particulate matter standards on the hog fuel fired boiler are subject to CAM. These include the PM<sub>2.5</sub> and PM<sub>10</sub> emission limits on the hog fuel fired boiler that are in the permit to construct issued for that source. According to the discussions in the SOB of the underlying PTC issued on November 16, 2016, the CAM requirements are satisfied by complying with the boiler MACT monitoring requirements. Refer to the SOB for PTC No. P-2013.0005 project 61632, issued November 16, 2016, for more details.

**7.8 Acid Rain Permit (40 CFR 72-75)**

The facility is not subject to acid rain permit.

**8. PUBLIC COMMENT**

As required by IDAPA 58.01.01.364, a public comment period was made available to the public from November 19 to December 20, 2018. During this time, comments were not submitted in response to DEQ's proposed action.

## **9. EPA REVIEW OF PROPOSED PERMIT**

As required by IDAPA 58.01.01.366, DEQ provided the proposed permit to EPA Region 10 for its review and comment on December 21, 2018 via EPA Electronic Permit System. No comments were received from EPA after EPA's 45-day review period.

## Appendix A - Emissions Inventory

**IDAHO FOREST GROUP - CHILCO, IDAHO**  
**POTENTIAL TO EMIT**  
**Emission Inventory/Calculations**

<b>Point Sources</b>	<b>PM10 (ton/yr)</b>	<b>PM2.5 (ton/yr)</b>	<b>SO2 (ton/yr)</b>	<b>NOx (ton/yr)</b>	<b>VOCs (ton/yr)</b>	<b>CO (ton/yr)</b>	<b>HAPS (ton/yr)</b>
<b>Lumber Drying</b>							
LUMBER DRY KILNS	6.18	5.36	---	---	238.5	---	23.8
<b>Sawmill Point Sources</b>							
SAWMILL CHIP BIN VENT - POINT SOURCE	6.27	1.88	---	---	---	---	---
SAWDUST BIN VENT - POINT SOURCE	2.65	0.80	---	---	---	---	---
<b>Planer Point Sources</b>							
PLANER CHIPPER TARGET BOX - POINT SOURCE	0.40	0.12	---	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE	5.44	1.63	---	---	---	---	---
<b>Steam Plant</b>							
KIPPER & SONS HOG FUEL BOILER	30.4	30.4	12.66	111.39	8.6	249.4	21.7
NEW NATURAL GAS BOILER	0.22	0.18	0.25	26.05	2.28	15.86	0.78
<b>Point Source Totals (tpy)</b>	<b>51.55</b>	<b>40.37</b>	<b>12.91</b>	<b>137.45</b>	<b>249</b>	<b>265</b>	<b>46.4</b>
<b>Point Source Totals (lb/hr)</b>	<b>11.8</b>	<b>9.21</b>	<b>3.18</b>	<b>33.4</b>		<b>65.20</b>	

**IDAHO FOREST GROUP - CHILCO**  
**Emission Inventory/Calculations**  
 PTE Production

Lumber Production			
Sawmill	325,000	mbdt/year	
Dry Kilns	325,000	mbdt/year	
Planer	325,000	mbdt/year	
Logs Used	1,170,000	tons/year	
Sawmill Hours	5,200	hours/year, est	
Planer Hours	5,200	hours/year	

Hog Fuel Boiler 607,594 1000 lbs/yr Steam Produced

Residuals Production			
Sawmill Chips	tons/year	Actual	BDT/mbf sawmill
Sawdust	158,925	978	BDT/mbf sawmill
Hog Bark	69,550	428	Tons burned, from heat
Planer Chips	92,060	48	BDT/mbf planer
Shavings	7,800	166	BDT/mbf planer
	26,975		

**KIPPER & SONS HOG FUEL BOILER****Proposed Emissions**

75 klb steam/hr	Boiler Capacity
125 mmBtu/hr maximum	Boiler Capacity
1,6667 mmBtu/klb	
607,594 klb steam, rolling 12-month	Permit Limit, unchanged
1,012,657 MMBtu/yr maximum	Based on permit limit

**CRITERIA POLLUTANTS**

PM10/PM2.5 (controlled), old permit limit, less stringent than MACT limit.		
Emissions:	30.4 tons/year	Current Permit Limit, used in modeling
	6.93 lbs/hr	Current Permit Limit, used in modeling
PM, front and back half, based on MACT limit		
PM10/PM2.5 (controlled), based on MACT limit.		
Emission Factor:	0.054 lb/mmBtu	MACT limit of 0.037 plus AP-42 factor
Emissions:	27.34 tons/year	for condensable PM of 0.017 lb/MMBtu
	6.75 lbs/hr	
Sulfur Dioxide:		
Emission Factor:	0.025 lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Emissions:	12.66 tons/year	Unchanged
	3.125 lbs/hr	
Nitrogen Oxides (NOx)		
Emission Factor:	0.22 lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Emissions:	111.39 tons/year	Unchanged
	27.50 lbs/hr	
Volatile Organic Compounds (VOC)		
Emission Factor:	0.017 lb/mmBtu	AP-42 TABLE 1.6-2, Rev 9/03
Emissions:	8.61 tons/year	Unchanged
	2.13 lbs/hr	
Lead (Pb)		
Emission Factor:	4.80E-05 lb/mmBtu	(AP-42 TABLE 1.6-4, Rev 9/03)
Emissions:	3.038 tons/year	Unchanged
	6.00E-03 lbs/hr	
Carbon Monoxide (CO)		
Emission Factor:	0.821 lb/1000 lb steam	Proposed Permit Limit
Emissions:	249.42 tons/year	Proposed Permit Limit
	61.58 lbs/hr	Max based on boiler capacity
Carbon Monoxide (CO)		
Emission Factor:	0.785 lb/1000 lb steam	Current Permit Limit
Emissions:	238.48 tons/year	Current Permit Limit
	58.88 lbs/hr	Max based on boiler capacity
Greenhouse Gas Calculations		
Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)		
Emission Factor:	207 lb/mmBtu	Greenhouse Gas Emissions (CH4, N2O, CO2e [Carbon Dioxide equivalent]) use emission factors from the Mandatory Greenhouse Gas Reporting Rule, 40 CFR Part 98 - Table C-2 - Wood Fuel and Table A-1 (Global Warming Potential GWP).
Emissions:	104,810 tpy CO2	
Methane		
Emission Factor:	0.01584 lb/mmBtu	
Emissions:	8.0 tpy	
	182.28 metric tons CO2e, GWP = 25	
Nitrous Oxide		
Emission Factor:	0.00792 lb/mmBtu	
Emissions:	4.01 tpy	
	1,086.38 metric tons CO2e, GWP = 298	
Metric tons CO2e	1,268.66	

**NEW NATURAL GAS BOILER****Burners Modified to Restrict heat input to <100 MMBtu/hr**

8,760 Hours/Year  
 80,000 pph steam, approx.  
 94,618 scfh gas, manufacturer  
 1,000 btu/cf gas - low estimate  
 94.6 mmBtu/hr  
 0.095 mmscf gas per hour  
 829 mmscf gas per year

**CRITERIA POLLUTANTS****PM10**

Emission Factor: 0.52 lb/mmscf  
 Emissions: 0.216 tons/year  
 0.0492 lb/hr

EPA NEI Emission Factors Revised  
 March 30, 2012

**PM2.5**

Emission Factor: 0.43 lb/mmscf  
 Emissions: 0.178 tons/year  
 0.0407 lb/hr

EPA NEI Emission Factors Revised  
 March 30, 2012

**Sulfur Dioxide:**

Emission Factor: 0.6 lb/mmscf  
 Emissions: 0.249 tons/year  
 0.057 lb/hr

(AP-42 TABLE 1.4-2, Rev 7/98)

**Nitrogen Oxides (NOx) as NO2**

Emission Factor: 62.87 lb/mmscf  
 Emissions: 26.05 tons/year  
 5.95 lb/hr

Based on 50 ppm @ 3% O2  
 Manufacturer Specifications

**Volatile Organic Compounds (VOC)**

Emission Factor: 5.5 lb/mmscf  
 Emissions: 2.279 tons/year  
 0.520 lb/hr

(AP-42 TABLE 1.4-2, Rev 7/98)

**Carbon Monoxide (CO)**

Emission Factor: 38.27 lb/mmscf  
 Emissions: 15.86 tons/year  
 3.62 lb/hr

Based on 50 ppm @ 3% O2  
 Manufacturer Specifications

**Development of NOx and CO Emission Factors**

f-factor natural gas, 0% O2 8710 dscf/MMBtu  
 Gas vol at Std conditions 379.49 dscf/lbmol  
 Mass exhaust flow at 3% O2 27 lbmol/MMBtu  
 Gas Heat Content 1020 mmBtu/mmscf

NO2 PPM 50 ppm @3% O2  
 NO2 Molecular Weight 46 lb/lbmol  
 NO2 Emissions 62.87 lb/mmscf

CO PPM 50 ppm @3% O2  
 CO Molecular Weight 28 lb/lbmol  
 CO Emissions 38.27 lb/mmscf

**Greenhouse Gas Emissions**

Natural Gas Combustion 850,404 MMBtu/year

**Carbon Dioxide (CO2)**

Emission Factor: 53.02 kg/MMBtu  
 Emissions: 45,088 metric tons CO2  
 49,597 tpy  
 45,088 metric tons CO2e, GWP = 1

**Methane**

Emission Factor: 0.001 kg/MMBtu  
 Emissions: 0.85 metric tons CO2  
 0.94 tpy  
 17.86 metric tons CO2e, GWP = 21

**Nitrous Oxide**

Emission Factor: 1.00E-04 kg/MMBtu  
 Emissions: 0.09 metric tons CO2  
 0.09 tpy  
 26.36 metric tons CO2e, GWP = 310

Metric tons CO2e 45,132.63

Greenhouse Gas Emissions  
 (CH4, N2O, CO2, CO2e [Carbon  
 Dioxide equivalent]) uses  
 emission factors from the  
 Mandatory Greenhouse Gas  
 Reporting Rule. 40 CFR Part 98 -  
 Table C-1, Table C-2 - Wood Fuel  
 and Table A-1 (Global Warming  
 Potential GWP).

**IDAHO FOREST GROUP - CHILCO BOILER**
**HAZARDOUS AIR POLLUTANTS (HAPS)**
**Operating Parameters:**

Potential Hours of Operation

8,760 hours/yr

Annual Boiler Heat Input, actual

1,012,657 mmBtu /yr

**Emission Factors:**

AP-42 Ch.1 6, Tables 1.6-3 and 1.6-4 (9/03)	Emission Factor (lb/mmBtu)	Total Annual Emissions (tons/yr)
Acetaldehyde	8.3E-04	4.20E-01
Acetophenone	3.2E-09	1.62E-06
Acrolein	4.0E-03	2.03E+00
Benzene	4.2E-03	2.13E+00
Benzo(a)pyrene	2.6E-06	1.32E-03
bis(2-ethylhexyl)phthalate	4.7E-08	2.38E-05
Bromomethane (methyl bromide)	1.5E-05	7.59E-03
2-Butanone (MEK)	5.4E-06	2.73E-03
Carbon tetrachloride	4.5E-05	2.28E-02
Chlorine	7.9E-04	4.00E-01
Chlorobenzene	3.3E-05	1.67E-02
Chloroform	2.8E-05	1.42E-02
Chloromethane (Methyl Chloride)	2.3E-05	1.16E-02
1,2-Dichloroethane	2.9E-05	1.47E-02
Dichloromethane (Methylenechloride)	2.9E-04	1.47E-01
1,2-Dichloropropane (Propylene dichloride)	3.3E-05	1.67E-02
Ethylbenzene	3.1E-05	1.57E-02
Formaldehyde (Permit Limit = 2.41 tpy)	4.4E-03	2.23E+00
Hydrogen chloride (MACT limit)	2.2E-02	1.11E+01
Methanol (from ODEQ)	1.4E-03	7.09E-01
Naphthalene	9.7E-05	4.91E-02
4-Nitrophenol	1.1E-07	5.57E-05
Pentachlorophenol	5.1E-08	2.58E-05
Phenol	5.1E-05	2.58E-02
Polycyclic Organic Matter (POM)	2.9E-06	1.46E-03
Benzo(a)anthracene	6.5E-08	
Benzo(a)pyrene	2.6E-06	
Benzo(b)fluoranthene	1.0E-07	
Benzo(k)fluoranthene	3.6E-08	
Indeno(1,2,3-cd)pyrene	8.7E-08	
Styrene	1.9E-03	9.62E-01
2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.6E-12	4.35E-09
Toluene	9.2E-04	4.66E-01
1,1,1-Trichloroethane (Methyl Chloroform)	3.1E-05	1.57E-02
2,4,6-Trichlorophenol <	2.2E-08	1.11E-05
Vinyl Chloride	1.8E-05	9.11E-03
o-Xylene	2.5E-05	1.27E-02
Antimony	7.9E-06	4.00E-03
Arsenic	2.2E-05	1.11E-02
Beryllium	1.1E-06	5.57E-04
Cadmium	4.1E-06	2.08E-03
Chromium, total	2.1E-05	1.06E-02
Chromium, hexavalent	3.5E-06	1.77E-03
Cobalt	6.5E-06	3.29E-03
Lead	4.8E-05	2.43E-02
Manganese	1.6E-03	8.10E-01
Mercury (MACT limit)	5.7E-06	2.89E-03
Nickel	3.3E-05	1.67E-02
Selenium	2.8E-06	1.42E-03
<b>TOTAL HAPS</b>		<b>21.75</b>

**Natural Gas Boiler HAPs**
**Operating Parameters:**

Potential Hours of Operation

New Boiler

8,760 hours/yr

Annual Gas Input

829 mmscf/yr

**Emission Factors:**

AP-42 Ch.1.4, Tables 1.4-3 and 1.4-4 (7/98) emission factors	Emission Factor (lb/mmscf)	Total Annual (tons/yr)	Total Annual (lb/yr)
Acenaphthene	1.8E-06	7.46E-07	1.49E-03
Acenaphthylene	1.8E-06	7.46E-07	1.49E-03
Anthracene	2.4E-06	9.95E-07	1.99E-03
Benzene	2.1E-03	8.70E-04	1.74E+00
Benzo(a)pyrene	1.2E-06	4.97E-07	9.95E-04
Benzo(g,h,i)perylene	1.2E-06	4.97E-07	9.95E-04
7,12-Dimethylbenz(a)anthracene	1.6E-05	6.63E-06	1.33E-02
Dichlorobenzene	1.2E-03	4.97E-04	9.95E-01
Fluoranthene	3.0E-06	1.24E-06	2.49E-03
Fluorene	2.8E-06	1.16E-06	2.32E-03
Formaldehyde	7.5E-02	3.11E-02	6.22E+01
Hexane	1.8E+00	7.46E-01	1.49E+03
2-Methylnaphthalene	2.4E-05	9.95E-06	1.99E-02
3-Methylchloranthrene	1.8E-06	7.46E-07	1.49E-03
Naphthalene	6.1E-04	2.53E-04	5.06E-01
Phenanthrene	1.7E-05	7.05E-06	1.41E-02
Pyrene	5.0E-06	2.07E-06	4.14E-03
Polycyclic Organic Matter (POM)	1.2E-05	4.97E-06	9.95E-03
Benzo(a)anthracene	1.8E-06		
Benzo(a)pyrene	1.2E-06		
Benzo(b)fluoranthene	1.8E-06		
Benzo(k)fluoranthene	1.8E-06		
Chrysene	1.8E-06		
Dibenzo(a,h)anthracene	1.8E-08		
Indeno(1,2,3-cd)pyrene	1.8E-06		
Toluene	3.4E-03	1.41E-03	
Arsenic	2.4E-04	9.95E-05	2.82E+00
Beryllium	1.2E-05	4.97E-06	1.99E-01
Cadmium	1.1E-03	4.56E-04	9.95E-03
Chromium	1.4E-04	5.80E-05	9.12E-01
Cobalt	8.4E-05	3.48E-05	1.16E-01
Manganese	3.8E-04	1.57E-04	6.96E-02
Mercury	2.6E-04	1.08E-04	3.15E-01
Nickel	2.1E-03	8.70E-04	2.16E-01
Selenium	2.4E-05	9.95E-06	1.74E+00
<b>TOTAL HAPS</b>	<b>1.887</b>	<b>0.78</b>	<b>1563.81</b>



# LUMBER DRY KILNS

Production Unchanged 325,000 mbdft/yr, lumber dried  
Production Unchanged 65,000 mbdft/kiln/yr

## CRITERIA POLLUTANTS

890.4109589 37.10045662

PM10 :	Emission Factor:	0.038 lbs/1000 bd.ft.	Willamette Ind. 1998 Source Tests
	Unchanged Emissions	6.18 tons/year	See below.
	Unchanged Emissions	1.41 lb/hr	References available upon request.
PM2.5 :	Emission Factor:	0.033 lbs/1000 bd.ft.	Willamette Ind. 1998 Source Tests
	Unchanged Emissions	5.36 tons/year	See below.
	Unchanged Emissions	1.22 lb/hr	References available upon request.
VOC:	Emission Factor:	1.47 lbs/1000 bd.ft.	Based on weight emission factor
	Proposed Emissions	238.5 tons/year	Proposed Permit Limit
	Current Emissions	175.50 tons/year	Permit Limit

VOC emissions based on species-dependent weighted emission factor, using information below.

Wood Species:	% of Total	VOC as VOC (lb/MBdft)	Weighted (lb/MBdft)	Source of Emission Factor
Ponderosa Pine	26.2%	2.46	0.64	2007 OSU Study, interpolated for temperature 210 F
Douglas Fir (DF, DFL)	38.2%	1.03	0.39	2007 OSU Study, interpolated for temperature 220 F
Larch	0.0%	0.25	0.00	2007 OSU Study, test result for 235 F
Hemlock	0.0%	0.24	0.00	2007 OSU Study, interpolated for temperature 220 F
Grand (white) fir (WW)	0.0%	0.70	0.00	1996 U of I study
Hem Fir	6.5%	0.70	0.05	1996 U of I study
Lodgepole	0.0%	1.32	0.00	2007 OSU Study, interpolated for temperature 210 F
Spruce	0.0%	0.11	0.00	2007 OSU Study for spruce
Englemann Spruce/Lodge Pole (ESLP)	29.1%	1.32	0.38	2007 OSU Study, interpolated for temperature 210 F
Alpine Fir	0.0%	0.70	0.00	1996 U of I study
Cedar	0.0%	0.15	0.00	1996 U of I study
Any Other Type	0.0%	2.46	0.00	Highest factor
<b>TOTAL</b>	<b>100.0%</b>		<b>1.47</b>	

## Dry Kiln Emission Factors, based on research

Units are pounds per thousand board feet (lb/MBF)

1998 Source Test	PM Total (lb/MBF)	PM <sub>10</sub> (lb/MBF)	PM <sub>2.5</sub> (lb/MBF)
coastal hemlock	0.051	0.051	0.048
Douglas-fir	0.024	0.024	0.018
<b>Average</b>	<b>0.038</b>	<b>0.038</b>	<b>0.033</b>

Total PM was assumed to be PM10, Condensable fraction  
was determine to be PM2.5 fraction

**Riley Creek - Chilco**  
**Dry Kiln Haps**

**Potential to Emit**

\* white wood is Engleman spruce, white fir, etc.

**ENTER**

Total MBF processed	325,000	
% Douglas Fir /Larch	38.2%	124,150 MBF/Yr by species calculated by Total MBF * % species
% Hem Fir	6.5%	20,995
% Ponderosa Pine	26.2%	85,001
% ESLP	29.2%	94,998
% Cedar	0.0%	0
% AF (WW)	0.0%	0
	100%	325,143

EMISSION FACTORS: units of pounds per thousand board feet (lb/mbf)						
Pollutant	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propion-aldehyde	Acrolein
Douglas Fir / Larch	0.1700	0.0964	0.0033	0.0687	0.0007	0.0009
Hem Fir	0.2500	0.1328	0.0030	0.1039	0.0084	0.0018
Ponderosa Pine	0.1483	0.1021	0.0067	0.0334	0.0027	0.0034
ESLPAF	0.0915	0.0539	0.0030	0.0333	0.0005	0.0008
Cedar	0.0915	0.0539	0.0030	0.0333	0.0005	0.0008
AF (WW)	0.2500	0.1328	0.0030	0.1039	0.0084	0.0018

EMISSIONS units of pounds per year (lb/yr)						
Species	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propion-aldehyde	Acrolein
Douglas Fir / Larch	21104	11972	406	8531	89	106
Hem Fir	5248	2788	64	2182	176	39
Ponderosa Pine	12604	8677	570	2838	230	291
ESLP	8689	5121	284	3161	49	73
Cedar	0	0	0	0	0	0
AF (WW) or Other	0	0	0	0	0	0
TOTAL, lb/yr	47,645	28,557	1,324	16,711	543	509
TOTAL, ton/yr	23.82	14.28	0.66	8.36	0.27	0.25

**SAWMILL CHIP BIN VENT - POINT SOURCE**

Emissions based on permit limits in current permit.

	Sawmill Chips	250,792 BDT/yr (Permit Cond. 6.1, chips portion of 356,906 BDT/yr))	
PM10:			
	Emission Factor:	0.05 lbs/BDT	Idaho DEQ Target Box Factor (in App. A)
		6.27 tpy	Calculated Emission
	Emissions:	6.27 tons/year	Permit Limit
		1.4315 lb/hr	based on permit limit
PM25:			
	Emission Factor:	0.015 lbs/ton	30% of PM10 for material handling sources
	Emissions:	1.88 tons/year	Based on data from EPA's PM Claculator
		0.4295 lb/hr	

**SAWDUST BIN VENT - POINT SOURCE**

	Sawmill Sawdust	106,144 BDT/yr (Permit Cond. 6.1, sawdust portion of 356,906 BDT/yr))	
PM10:			
	Emission Factor:	0.05 lbs/ton	Idaho DEQ Target Box Factor.
		2.65 tpy	Calculated Emission
	Emissions:	2.65 tons/year	Permit Limit
		0.6050 lb/hr	based on permit limit
PM25:			
	Emission Factor:	0.015 lbs/ton	30% of PM10 for material handling sources
	Emissions:	0.80 tons/year	Based on data from EPA's PM Claculator
		0.1815 lb/hr	

**PLANER CHIPPER TARGET BOX - POINT SOURCE**

	Planer Chips	16,000 BDT/yr (Permit Cond. 9.5)	
PM10 :			
	Emission Factor:	0.05 lbs/ ton	Idaho DEQ Target Box Factor.
		0.40 tpy	Calculated Emission
	Emissions:	0.40 tons/year	Permit Limit
		0.0913 lb/hr	
PM2.5 :			
	Emission Factor:	0.015 lbs/ ton	30% of PM10 for material handling sources
	Emissions:	0.1200 tons/year	Based on data from EPA's PM Claculator
		0.02740 lb/hr	

**PLANER SHAVINGS CYCLONE BAGHOUSE - POINT SOURCE**

	Planer Chips	120,000 BDT/yr (Permit Cond. 9.6)	
		29,000 dscfm	Baghouse Throughput
		8,760 Hours per Year, potential	
PM10 :			
	Emission Factor:	0.005 gr/dscf	Baghouse Design
	Emissions:	5.44 tpy	Calculated Emission
		5.40 tpy	Permit Limit
		1.243 lb/hr	
PM25:			
	Emission Factor:	0.0015 gr/dscf	30% of PM10 for material handling sources
	Emissions:	1.63 tpy	Based on data from EPA's PM Claculator
		0.3729 lb/hr	

**Subtotals, Proposed and Current**

PM10 (tpy)	14.764
PM10 (lb/hr)	3.371
PM2.5 (tpy)	4.429
PM2.5 (lb/hr)	1.011

## **Appendix B - Facility Comments for Draft Permit**

**The following comments were received from the facility on October 29, 2018:**

**Facility Comment:** Page 11, condition 3.22. References Table 3.2, should be Table 3.1. Page 12, condition 3.23. References Table 3.3, should be Table 3.2.

**DEQ Response:** corrections are made.

**Facility Comment:** Page 17, condition 3.27. This requires the source test report within 30 days, unless IFG requests an extension. The Boiler MACT source test reports are due within 60 days, so this is confusing. Can you change this requirement to make the source test report due within 60 days?

**DEQ Response:** a change is made by using the standard language in the current Tier I permit template.

**Facility Comment:** Page 20, condition 4.2. I can't figure out why this boiler still has a formaldehyde limit, even though Boiler MACT applies. IFG can easily comply, so this is just a matter of interest.

**DEQ Response:** Permit Condition 4.2 is changed to "reserved". Refer to the discussions in Facility-Wide Conditions section, under Permit Condition 4.2 of the SOB.

**Facility Comment:** Boiler MACT conditions in general: In some places it says "the permittee", and in other places "you". There are 27 instances of "you". What is the DEQ opinion on putting "you" in the permit?

**DEQ Response:** "you" is used in the boiler MACT. To be consistent with DEQ's permit, each "you" has been replaced with "the permittee" in the permit.

**Facility Comment:** Page 65, condition 8.5. There seems to be an extra sentence fragment at the end of this condition.

**DEQ Response:** it is removed.

**Facility Comment:** Page 72, Section 9, summary Description. The sentence above Table 9.2 references sawmill sources. It should say: 'Table 9.1 contains only a summary of the requirements that apply to the planer shavings cyclone and the planer chip bin target box.'

**DEQ Response:** changes are made.

## **Appendix C – Regulatory Analysis**

## **Appendix C.1 - 40 CFR 60, Subpart Dc**

## REGULATORY ANALYSIS FOR ATTACHMENT TO IDAHO FORM FRA IFG-CHILCO

### PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART DC—STANDARDS OF PERFORMANCE FOR SMALL INDUSTRIAL-COMMERCIAL- INSTITUTIONAL STEAM GENERATING UNITS

#### §60.40C APPLICABILITY AND DELEGATION OF AUTHORITY.

- (a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

IFG Chilco is subject to NSPS Subpart Dc because it has a natural gas-fired steam generating boiler that is 94.6 MMBtu/hr and was manufactured after June 9, 1989.

- (b) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO<sub>2</sub>) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

The natural gas boiler is not subject to SO<sub>2</sub> or PM emission limits under this subpart.

#### §60.42C STANDARD FOR SULFUR DIOXIDE (SO<sub>2</sub>).

The natural gas boiler is not subject to SO<sub>2</sub> emission limits under this subpart.

#### §60.43C STANDARD FOR PARTICULATE MATTER (PM).

The natural gas boiler is not subject to PM emission limits under this subpart.

#### §60.48C REPORTING AND RECORDKEEPING REQUIREMENTS.

- (a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

- (1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

IDEQ has been notified of the design capacity, and fuel type.

- (g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

IFG-Chilco keeps and will continue to keep records of the amount of natural gas fuel combusted daily.

- (2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas... may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

IFG-Chilco will keep daily and monthly records of the amount of natural gas combusted.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility ... where the only fuels combusted in any steam generating unit ... are natural gas... may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

IFG-Chilco may decide to use a certificate in lieu of fuel monitoring. If so, monthly records of the fuel delivered will be kept.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

IFG-Chilco will maintain fuel records for tat least 2 years following the recording date.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

No reports are required for natural gas boilers. Records are kept onsite for IDEQ review.



## Appendix C.2 - 40 CFR 63, Subpart ZZZZ

## REGULATORY ANALYSIS FOR ATTACHMENT TO IDAHO FORM FRA IFG – CHILCO

### **PART 63\_ NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE. Subpart ZZZZ\_ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines**

#### **§ 63.6585 *Am I subject to this subpart?***

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions ... (a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile.

The Chilco fire-water pump engine is a diesel-fired (compression ignition) RICE. IFG's Chilco facility is a Major Source of HAP.

#### **§ 63.6590 *What parts of my plant does this subpart cover?***

This subpart applies to each affected source... (ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

The Chilco fire-water pump engine is an affected source. It is an existing stationary RICE with a site rating of 150 brake HP and was installed in 2004.

#### **§ 63.6595 *When do I have to comply with this subpart?***

(a) *Affected sources.* (1) If you have ... an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions... you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013.

#### **§ 63.6602 *What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?***

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you.

The following are the portions of Table 2C to Subpart ZZZZ of Part 63 which apply to the firewater pump at IFG – Chilco.

**Table 2c to Subpart ZZZZ of Part 63—**

<b>For each . . .</b>	<b>You must meet the following requirement, except during periods of startup . . .</b>	<b>During periods of startup you must . . .</b>
<b>1. Emergency stationary CI RICE and black start stationary CI RICE.<sup>1</sup></b>	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; <sup>2</sup> b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. <sup>3</sup>	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. <sup>3</sup>

<sup>1</sup> If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

<sup>2</sup> Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

<sup>3</sup> Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

The Chilco fire-water pump engine is an emergency engine. It is only used for fire suppression. It is tested regularly to ensure readiness. IFG reserves the right to use the options referenced in footnotes 2 and 3 to Table 2c, and described in § 63.6625(i)

**§ 63.6605 What are my general requirements for complying with this subpart?**

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. . .

IFG Chilco must comply with the general requirements of the Subpart.

**§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance**

**requirements?** (e) If you own or operate any of the following stationary RICE (an existing emergency stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions) you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. (f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions you must install a non-resettable hour meter if one is not already installed.

IFG Chilco must follow a maintenance plan based on the manufacturer's instructions for maintenance and operation of the engine as described above. The engine must be equipped with a non-resettable hour meter.

**§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?**

IFG must comply with the following conditions for operation of the emergency fire-water pump engine.

**(f) Requirements for emergency stationary RICE.** (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions...you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing.

**§ 63.6645 What notifications must I submit and when?**

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, **an existing stationary emergency RICE**, or an existing stationary RICE that is not subject to any numerical emission standards.

According to 63.6645(5), notifications are not required for an existing stationary emergency CI RICE. IFG understands that notification is not required for the fire-water pump engine.

**§ 63.6650 What reports must I submit and when?**

(a) You must submit each report in Table 7 of this subpart that applies to you.

No reports in Table 7 apply.

**Sec. 63.6655 What records must I keep?**

IFG must keep records of engine operation for 5 years, as described below.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the nonresettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

## Appendix C.3 - 40 CFR 63, Subpart DDDDD

**Title 40: Protection of Environment. Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAPS). Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters**

Based on Regulation obtained from eCFR on January 31, 2016. Regulation Version is: [76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013; 80 FR 72806, Nov. 20, 2015]

Only sections of the regulation that are could possibly be applicable to IFG are included. Comments related IFG's compliance methodology are in green font and are underlined.

**§ 63.7485 Am I subject to this subpart?**

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575. IFG operates industrial boilers at the Chilco sawmill and is subject to this subpart (DDDDD). The Chilco sawmill is a major source of HAP emissions.

**§ 63.7490 What is the affected source of this subpart?**

§ 63.7490(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section. (1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575. (2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in § 63.7575, located at a major source.

§ 63.7490(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction. The natural gas (gas 1) boiler is a new boiler which will be installed at the facility in 2016.

§ 63.7490(c) A boiler or process heater is reconstructed ... Does not apply.

§ 63.7490(d) A boiler or process heater is existing if it is not new or reconstructed. The Chilco wood-fired (hog fuel) boiler is an affected source and is an existing boiler.

§ 63.7490(e) An existing electric utility steam generating unit (EGU) ... Does not apply.

**§ 63.7491 Are any boilers or process heaters not subject to this subpart?** IFG- Chilco does not have any boilers or process heaters that are not subject to this subpart.

**§ 63.7495 When do I have to comply with this subpart?**

§ 63.7495(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by April 1, 2013, or upon startup of your boiler or process heater, whichever is later. The natural gas boiler will be a new source and must comply with applicable work practices, summarized in Table 3, upon startup.

§ 63.7495(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i). IFG has been granted a one-year extension for compliance as provided in § 63.6(i). The applicable compliance date is January 31, 2017.

§ 63.7495(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP... Does not apply to IFG-Chilco.

§ 63.7495(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart. Notification compliance is discussed under § 63.7545.

§ 63.7495(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, ... Does not apply.

§ 63.7495(f), (g), (h), (i) ... Do not apply.

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**§ 63.7499 What are the subcategories of boilers and process heaters?**

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

- (a) Pulverized coal/solid fossil fuel units.
- (b) Stokers designed to burn coal/solid fossil fuel.
- (c) Fluidized bed units designed to burn coal/solid fossil fuel.
- (d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.
- (e) Fluidized bed units designed to burn biomass/bio-based solid.
- (f) Suspension burners designed to burn biomass/bio-based solid.
- (g) Fuel cells designed to burn biomass/bio-based solid.
- (h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.
- (i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid. The IFG-Chilco hog fuel boiler falls into this subcategory.
- (j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.
- (k) Units designed to burn liquid fuel that are non-continental units.
- (l) Units designed to burn gas 1 fuels. The natural gas (gas 1) boiler falls into this subcategory.
- (m) Units designed to burn gas 2 (other) gases.
- (n) Metal process furnaces.
- (o) Limited-use boilers and process heaters.
- (p) Units designed to burn solid fuel.
- (q) Units designed to burn liquid fuel.
- (r) Units designed to burn coal/solid fossil fuel.
- (s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.
- (t) Units designed to burn heavy liquid fuel.
- (u) Units designed to burn light liquid fuel.

~~~~~  
**§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?**  
Tables are listed at the end of this analysis.

§ 63.7500(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the



affected unit is operating, except as provided in paragraph (f) of this section. IFG will meet the requirements.

§ 63.7500(a)(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under §63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate either steam, cogenerate steam with electricity, or both. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart..

Table 1 contains no emission limits for new boilers burning gas 1 fuel, so there are no emission limits that apply to the natural gas boiler.

Table 2 contains the applicable emission limits for existing boilers that apply to the hog fuel boiler: HCl, mercury, CO and PM.

Table 3 contains applicable work practice standards for the hog fuel boiler and the natural gas boiler. The hog fuel boiler will have to have annual tune-ups and a one-time energy assessment. The natural gas boiler is retained, it will also have to have annual tune-ups and a one-time energy assessment.

The startup and shutdown requirements in Items 5 and 6 of Table 3 are applicable and have been revised to allow clean dry biomass during startup.

§ 63.7500(a)(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

Table 4 contains operating limits for the hog fuel boiler. MACT limits the opacity to 10% (daily block average), while the permit allows 20% over a 3-minute average. MACT requires that the boiler can only be operated at 110% of the average steaming limit during the PM source test.

§ 63.7500(a)(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. IFG currently meets this requirement and will continue to comply.

§ 63.7500(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section. IFG will request approval for alternative work practice standards if needed.

§ 63.7500(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the



operating limits in Table 4 to this subpart. IFG does not have or expect to have any limited use boilers or process heaters.

§ 63.7500(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540. ... Does not apply.

§ 63.7500(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart. The IFG natural gas boiler is larger than 10 million Btu/hr and does not have an oxygen trim system. Annual tune-ups will be required.

§ 63.7500(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with items 5 and 6 of Table 3 to this subpart. The opacity and emission limits on the hog fuel boiler do not apply during startup and shutdown.

~~~~~  
**§ 63.7501 Reserved.**

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**§ 63.7505 What are my general requirements for complying with this subpart?**

§ 63.7505(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f). IFG will comply with all applicable emission limits, work practice standards and operating limits in this subpart, as summarized in Tables 2, 3 and 4.

§ 63.7505(b) [Reserved]

§ 63.7505(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart. IFG will use source testing and fuel analysis as appropriate to demonstrate compliance. Note that the COMS has been removed from this section because opacity is not an emission limit.

**§ 63.7505(d)** If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through the use of CPMS, or with a CEMS or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses

design, data collection, and the quality assurance and quality control elements outlined in §63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of §63.7525. Using the process described in §63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

IFG will develop a site-specific monitoring plan for the COMS.

Because the permittee demonstrates compliance with applicable emission limits (e.g., CO and PM) through performance testing and subsequent compliance with operating limits, including the use of CPMS (e.g., oxygen analyzer and boiler steam rate monitor), the permittee shall develop a site-specific monitoring plan according to the requirements in 40 CFR 63.7505(d)(1) through (4) for the use of any CPMS

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#### **§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?**

§ 63.7510(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

§ 63.7510(a)(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart. IFG will comply.

§ 63.7510(a)(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section. IFG will comply.

§ 63.7510(a)(2)(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart. Noted.

§ 63.7510(a)(2)(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels. Does not apply

§ 63.7510(a)(2)(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section. Noted.

§ 63.7510(a)(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart. Compliance is discussed under § 63.7530

§ 63.7510(a)(4) Conduct CMS performance evaluations according to § 63.7525. IFG will need to install a CMS for opacity (COMS) on the hog fuel boiler and will conduct the performance evaluations as required.

§ 63.7510(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. ... IFG will use either fuel testing or source testing for HCl and mercury compliance. PM testing will be used as allowed for TSM compliance demonstration.

§ 63.7510(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section. IFG will source test the hog fuel boiler for CO.

§ 63.7510(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart. IFG will source test the hog-fuel boiler for PM.

§ 63.7510(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph



(j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. The hog-fuel boiler source tests are due by July 29, 2017 based on the one-year compliance extension granted by the Administrator.

§ 63.7510(f) For new or reconstructed affected sources... The natural gas boiler is a new gas 1 boiler, and is not subject to any emission limits.

§ 63.7510(g) For new or reconstructed affected sources (as defined in §63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in §63.7515(d) following the initial compliance date specified in §63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in §63.7515(d). The first tune-up for the natural gas boiler will be completed when the boiler is installed and starts operating.

§ 63.7510(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) ... Does not apply.

§ 63.7510(i) For an existing EGU that becomes subject after January 31, 2013... Does not apply.

§ 63.7510(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495. Noted.

§ 63.7510(k). For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months. Noted.

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#### **§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?**

§ 63.7515(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section. IFG will schedule source tests as required.

§ 63.7515(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. This provision is similar to the current permit. IFG will schedule source tests as required/allowed under the rule.

If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. IFG has no current plans to use emission averaging.

The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM. IFG may source test for HCl and TSM (PM as a surrogate). IFG will comply with the maximum chloride and maximum TSM input requirements as necessary.

§ 63.7515(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart). This provision is similar to the current permit. IFG will schedule source tests as required under the rule.

§ 63.7515(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to §63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in §63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in §63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in §63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in §63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after April 1, 2013 or the initial startup of the new or reconstructed affected source, whichever is later. IFG will schedule boiler tune-ups as required under the rule.

§ 63.7515(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to §63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level. If sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply. If IFG chooses to use fuel analysis, the sampling program will comply with the schedule in Paragraph (e).

§ 63.7515(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550. IFG will report results of performance tests and fuel analyses in the specified time frame. Boiler operating levels during the source tests will be documented.

§ 63.7515(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in

§ 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up. Noted.

§ 63.7515(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory ... Does not apply.

§ 63.7515(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a). IFG does not plan to use a CO CEMS.

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#### **§ 63.7520 What stack tests and procedures must I use?**

§ 63.7520(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Source test protocols will be submitted as required and equipment will be operated during testing as required by the EPA reference methods.

§ 63.7520(b) You must conduct each performance test according to the requirements in Table 5 to this subpart. Source tests will be performed following the appropriate EPA reference methods.

§ 63.7520(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart. This may not apply because the hog fuel boiler is a single fuel boiler. Chlorine and mercury concentrations in the hog fuel are only trace amounts and vary naturally.

§ 63.7520(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart. Each test will comply with the reference method requirements.

§ 63.7520(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates. Source test results will be converted to heat-input basis using the F-Factors as required.

§ 63.7520(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method



detection level. If measured emissions are below the detection limit, the detection limit will be used as the measured emission level.

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**§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?**

§ 63.7521(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. This section applies to hog fuel (wood, biomass).

For gas 2 (other) fuels... Does not apply.

You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart. This section applies to hog fuel only, not to natural gas (gas 1).

§ 63.7521(b) *et seq.* You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in §63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

IFG will provide the site-specific fuel monitoring plan as required.

§ 63.7521(c) You must obtain composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material. At a minimum, for demonstrating initial compliance by fuel analysis, you must obtain three composite samples. For monthly fuel analyses, at a minimum, you must obtain a single composite sample. For fuel analyses as part of a performance stack test, as specified in §63.7510(a), you must obtain a composite fuel sample during each performance test run.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

IFG will collect fuel samples as required. Details will be provided in the fuel monitoring plan.

§ 63.7521(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

IFG will prepare fuel samples as required. Details will be provided in the fuel monitoring plan.

§ 63.7521(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart. IFG will follow the specified procedures and use the required calculations.

§ 63.7521(f) To demonstrate that a gaseous fuel other than natural gas ... Does not apply.

§ 63.7521(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels ... Does not apply.



§ 63.7521(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels. Does not apply.

§ 63.7521(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type ... Does not apply.

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**§ 63.7522 Can I use emissions averaging to comply with this subpart?**

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average. IFG-Chilco does not have more than one existing boiler in any subcategory. This section does not apply.

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**§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?**

§ 63.7525(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (6) of this section.

§ 63.7525(a)(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. IFG has an oxygen analyzer system in place and does not intend to install a CO CEMS.

§ 63.7525(a)(2) To demonstrate compliance with the applicable alternative CO CEMS emission ... Does not apply. IFG does not plan to install a CO CEMS.

§ 63.7525(a)(3) – (6) ... Do not apply because IFG does not plan to use a CO CEMS.

§ 63.7525(a)(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart. The oxygen level measured during the CO MACT compliance test becomes the lower set point for the oxygen trim system. If IFG operates an oxygen trim system on the Chilco boiler, this requirement will be met.

§ 63.7525(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory ... Does not apply.

§ 63.7525(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495. IFG will install and operate a COMS on the ESP stack. IFG will install the COMS as required before the January 31, 2017 compliance date.

§ 63.7525(c)(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter. The COMS installation will conform to PS1.

§ 63.7525(c)(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter. The COMS calibration and certification will conform to PS1.

§ 63.7525(c)(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. The COMS will be set up as required.

§ 63.7525(c)(4) The COMS data must be reduced as specified in § 63.8(g)(2). The COMS will be set up as required.

§ 63.7525(c)(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS. The COMS monitoring plan will include the calibration and audit requirements.

§ 63.7525(c)(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. The COMS will be operated and maintained according to the monitoring plan.

§ 63.7525(c)(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control. The COMS will be programmed to provide the appropriate averages.

§ 63.7525(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495. Does not apply.

§ 63.7525(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.... Does not apply. IFG does not intend to install a gas flow monitoring system.

§ 63.7525(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section. .... Does not apply

§ 63.7525(g) If you have an operating limit that requires a pH monitoring system.... Does not apply

§ 63.7525(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, .... Does not apply.

§ 63.7525(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate .... Does not apply

§ 63.7525(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart .... Does not apply

§ 63.7525(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating. IFG will follow the requirements if they install or convert a boiler to limited use.

§ 63.7525(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl.... Does not apply

§ 63.7525(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO<sub>2</sub> CEMS, .... Does not apply

**§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?**

§ 63.7530(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to §63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by §63.7510(a)(2). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to §63.7525. IFG will demonstrate initial compliance by source testing or fuel analyses.

§ 63.7530(b) If you demonstrate compliance through performance stack testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in §63.7510(a)(2). (Note that §63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

§ 63.7530(b)(i)-(vii) and (ix) do not apply

(viii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

IFG will establish site-specific operating limits based on performance testing as required. IFG will follow all the applicable procedures listed in Paragraph (b).

§ 63.7530(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section. If demonstrating compliance through fuel analysis, IFG will follow all the applicable procedures listed in Paragraph (c).

§ 63.7530(d) Reserved

§ 63.7530(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.. IFG will provide appropriate notification for the energy assessment.

§ 63.7530(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e). IFG will provide all required notifications.

§ 63.7530(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575... Does not apply.

§ 63.7530(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of



Table 3 of this subpart. The work practices standards in Items 5 and 6 of Table 3 have been amended to allow the use of clean dry biomass during startup. IFG will comply.

§ 63.7530(i) If you opt to comply with the alternative SO<sub>2</sub> CEMS operating limit ... Does not apply.

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**§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?**

IFG may choose to use efficiency credits at Chilco, and will follow all the requirements of this section.

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**§ 63.7535 How do I monitor and collect data to demonstrate continuous compliance?**

§ 63.7535(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d). IFG will comply with this section of the regulation and the site-specific monitoring plan when collecting data from the COMS.

§ 63.7535(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable. Noted.

§ 63.7535(c) You may not use data recorded during periods of startup and shutdown, monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system. Noted.

§ 63.7535(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods of startup and shutdown, when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your semi-annual report. Noted.

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**§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?**

§ 63.7540(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating

limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section. Applicable portions of the tables are included at the end of this analysis.

§ 63.7540(a)(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests. Noted.

§ 63.7540(a)(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following: (i) equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis. (ii) equal to or lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing. IFG will keep appropriate records.

§ 63.7540(a)(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 16 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate. IFG may demonstrate HCl compliance through fuel analysis. The Chilco boiler only burns woody biomass, and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(4) *et seq.* If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels... IFG will likely demonstrate HCl compliance through source testing. The Chilco boiler only burns woody biomass and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(5) *et seq.* If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate. IFG may demonstrate mercury compliance through fuel analysis. The Chilco boiler only burns woody biomass and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate. IFG may demonstrate mercury compliance through source testing. The Chilco boiler only burns woody biomass and IFG does not foresee ever using a different fuel type.

§ 63.7540(a)(7) If your unit is controlled with a fabric filter... Does not apply.

§ 63.7540(a)(8) To demonstrate compliance with the applicable alternative CO CEMS ...IFG does not intend to use this provision of the rule.

§ 63.7540(a)(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS ...IFG does not intend to use this provision of the rule.

§ 63.7540(a)(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. This frequency does not apply to limited-use boilers and process heaters, as defined in §63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOX requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, a report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

IFG will conduct the annual boiler tune-ups on the hog fuel boiler as required. IFG will also tune-ups on the natural gas boiler as required.



§ 63.7540(a)(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour ... Does not apply.

§ 63.7540(a)(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in §63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up If IFG installs and operates a continuous oxygen trim system that maintains an optimum air to fuel ratio, they may switch to the 5-year tune up schedule for the hog fuel boiler.

§ 63.7540(a)(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. Noted.

§ 63.7540(a)(14) If you are using a CEMS measuring mercury emissions to meet requirements ... Does not apply.

§ 63.7540(a)(15) If you are using a CEMS to measure HCl emissions ... Does not apply.

§ 63.7540(a)(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels ... The IFG Chilco boiler burns only woody biomass and no other fuel is expected to be used.

§ 63.7540(a)(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel... The IFG Chilco boiler burns only woody biomass and no other fuel is expected to be used.

§ 63.7540(a)(18) If you demonstrate continuous PM emissions compliance with a PM CPMS ... Does not apply.

§ 63.7540(a)(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS ... Does not apply.

§ 63.7540(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550. IFG will comply with the deviation reporting requirements.

§ 63.7540(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory... Does not apply.

§ 63.7540(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart. IFG will comply with the work practice standards in Items 5 and 6 of Table 3.

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**§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?** IFG Chilco does not intend to use the emissions averaging provision because there is not more than one boiler in any one subcategory.

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**§ 63.7545 What notifications must I submit and when?**

§ 63.7545(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

§ 63.7(b) *Notification of performance test.* (1) The owner or operator of an affected source must notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin to allow the Administrator, upon request, to review and approve the site-specific test plan required under paragraph (c) of this section and to have an observer present during the test. IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test.

§ 63.7(c) *Quality assurance program.* (1) The results of the quality assurance program required in this paragraph will be considered by the Administrator when he/she determines the validity of a performance test. (2)(i) *Submission of site-specific test plan.* Before conducting a required performance test, the owner or operator of an affected source shall develop and, if requested by the Administrator, shall submit a site-specific test plan to the Administrator for approval. The test plan shall include a test program summary, the test schedule, data quality objectives, and both an internal and external quality assurance (QA) program. Data quality objectives are the pretest expectations of precision, accuracy, and completeness of data. The pre-test protocol for MACT compliance testing must meet the requirements of this section.

§ 63.8(e) *Performance evaluation of continuous monitoring systems — (1) General.* When required by a relevant standard, and at any other time the Administrator may require under section 114 of the Act, the owner or operator of an affected source being monitored shall conduct a performance evaluation of the CMS. Such performance evaluation shall be conducted according to the applicable specifications and procedures described in this section or in the relevant standard. (2) *Notification of performance evaluation.* The owner or operator shall notify the Administrator in writing of the date of the performance evaluation simultaneously with the notification of the performance test date required under § 63.7(b) or at least 60 days prior to the date the performance evaluation is scheduled to begin if no performance test is required. IFG will comply with the notification requirements for the hog fuel boiler COMS.

§ 63.8(f)(4 and 6) *Use of an alternative monitoring method.* IFG does not intend to use any alternative monitoring methods.

§ 63.9(b) *Initial notifications.* (1)(i) The requirements of this paragraph apply to the owner or operator of an affected source when such source becomes subject to a relevant standard... (2) The owner or operator of an affected source that has an initial startup before the effective date of a relevant standard under this part shall notify the Administrator in writing that the source is subject to the relevant standard. The notification, which shall be submitted not later than 120 calendar days after the effective date of the relevant standard (or within 120 calendar days after the source becomes subject to the relevant standard). IFG submitted the Subpart DDDDD initial notification on January 28, 2005 and again on May 15, 2013. This does not apply to the new natural gas boiler as the effective date of the standard is January 31, 2013 and the initial startup date of the new natural gas boiler is after that date.

§ 63.9(c) *Request for extension of compliance.* If the owner or operator of an affected source cannot comply with a relevant standard by the applicable compliance date for that source, or if the owner or operator has installed BACT or technology to meet LAER consistent with § 63.6(i)(5) of this subpart, he/she may submit to the Administrator (or the State with an approved permit program) a request for an extension of compliance as specified in § 63.6(i)(4) through § 63.6(i)(6). § 63.6(i)(4) through



§ 63.6(i)(6) would allow the state to grant up to 1 additional year to comply with the standard, if such additional period is necessary for the installation of controls. IFG has requested and been granted a one-year extension to allow replacement of the boiler EFB with an ESP.

§ 63.9(d) *Notification that source is subject to special compliance requirements.* An owner or operator of a new source that is subject to special compliance requirements as specified in §63.6(b)(3) and §63.6(b)(4) shall notify the Administrator of his/her compliance obligations not later than the notification dates established in paragraph (b) of this section for new sources that are not subject to the special provisions. This does not apply to the IFG Chilco boiler because it is an existing source. This does not apply to the new natural gas boiler either as it is not subject to special compliance requirements as specified in §63.6(b)(3) and §63.6(b)(4).

§ 63.9(e) *Notification of performance test.* The owner or operator of an affected source shall notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin to allow the Administrator to review and approve the site-specific test plan required under § 63.7(c), if requested by the Administrator, and to have an observer present during the test. IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test.

§ 63.9(f) *Notification of opacity and visible emission observations.* The owner or operator of an affected source shall notify the Administrator in writing of the anticipated date for conducting the opacity or visible emission observations specified in § 63.6(h)(5), if such observations are required for the source by a relevant standard. The notification shall be submitted with the notification of the performance test date, as specified in paragraph (e) of this section, or if no performance test is required or visibility or other conditions prevent the opacity or visible emission observations from being conducted concurrently with the initial performance test required under § 63.7, the owner or operator shall deliver or postmark the notification not less than 30 days before the opacity or visible emission observations are scheduled to take place. IFG will provide required notifications prior to opacity compliance tests.

§ 63.9(g) *Additional notification requirements for sources with continuous monitoring systems.* The owner or operator of an affected source required to use a CMS by a relevant standard shall furnish the Administrator written notification as follows: (1) A notification of the date the CMS performance evaluation under § 63.8(e) is scheduled to begin, submitted simultaneously with the notification of the performance test date required under § 63.7(b). ... (2) A notification that COMS data results will be used to determine compliance with the applicable opacity emission standard during a performance test required by § 63.7 in lieu of Method 9 or other opacity emissions test method data, ... The notification shall be submitted at least 60 calendar days before the performance test is scheduled to begin. IFG will submit all source test notifications at least 60 days prior to the scheduled test date.

§ 63.9(h) *Notification of compliance status.* (1) The requirements of paragraphs (h)(2) through (h)(4) of this section apply when an affected source becomes subject to a relevant standard.

§ 63.9(h)(3) After a title V permit has been issued to the owner or operator of an affected source [Applies because IFG Chilco has a Title V (Tier I) permit], the owner or operator of such source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this part. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this part, the owner or operator of such source shall submit the notification of compliance status to the appropriate permitting authority following completion of the relevant compliance demonstration activity specified in the relevant standard. IFG must submit compliance status reports to DEQ.

§ 63.7545(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013. IFG submitted the Subpart DDDDD initial notification on January 28, 2005 and again on May 15, 2013.

§ 63.7545(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. IFG will comply when the natural gas boiler is installed.

§ 63.7545(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin. IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test.

§ 63.7545(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8) of this section, as applicable. If you are not required to conduct an initial compliance demonstration as specified in §63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b). This applies to both boilers. Refer to the permit for details.

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under §241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of §241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in §63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in §63.7540(a)(10)(i) through (vi)."

(ii) "This facility has had an energy assessment performed according to §63.7530(e)."

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

The pre-test protocol for MACT compliance testing must meet the requirements of this section. IFG must review the pre-test protocol carefully before it is submitted by the testing firm.

§ 63.7545(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas... Does not apply.

§ 63.7545(g) If you intend to commence or recommence combustion of solid waste... Does not apply.

§ 63.7545(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory ... Does not apply. IFG does not anticipate switching fuels in any boilers.

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**§ 63.7550 What reports must I submit and when?**

§ 63.7550(a) You must submit each report in Table 9 to this subpart that applies to you.

§ 63.7550(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct subsequent annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first semi-annual compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in §63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in §63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

IFG can submit an annual compliance report for the natural gas boiler, to match the schedule of the tune-ups. IFG will submit semi-annual compliance reports for the hog fuel boiler. The first compliance report is for the period of January 31 – July 31, 2017. That report will be due January 31, 2018. The next compliance report will be for July 1 2017 to December 31, 2017, and will be due January 31, 2018. Subsequent reports will cover each calendar half and will be due at the end of July or January.

§ 63.7550(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.



- (5)(i) Company and Facility name and address.
- (ii) Process unit information, emissions limitations, and operating parameter limitations.
- (iii) Date of report and beginning and ending dates of the reporting period.
- (iv) The total operating time during the reporting period.
- (v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.
- (vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.
- (vii) If you are conducting performance tests once every 3 years consistent with §63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.
- (viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 16 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 17 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 18 of §63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).
- (ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of §63.7530 or the maximum mercury input operating limit using Equation 8 of §63.7530, or the maximum TSM input operating limit using Equation 9 of §63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.
- (x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with §63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in §63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO<sub>2</sub>, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

IFG will submit compliance reports with all the information specified in this paragraph.

§ 63.7550(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, or from the work practice standards for periods of startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

IFG will include all required information in the compliance report. The compliance report will follow this regulation to the letter.

§ 63.7550(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d). This section applies to opacity from the hog fuel boiler because it will have a COMs (opacity CMS). IFG will include all required information in the compliance report.

§ 63.7550(f)-(g) [Reserved]

§ 63.7550(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (<http://www.epa.gov/ttn/chief/ert/index.html>), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (<http://www.epa.gov/ttn/chief/cedri/index.html>), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

[78 FR 7183, Jan. 31, 2013, as amended at 80 FR 72814, Nov. 20, 2015]

IFG will submit all reports according to the requirements of this section. IFG will use EPA's electronic reporting systems to submit the reports to EPA.

#### **§ 63.7555 What records must I keep?**

§ 63.7555(a) You must keep records according to paragraphs (a)(1) and (2) of this section. (1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv). (2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii). (3) For units in the limited use subcategory... IFG must keep copies of all the notifications and reports they submit.

§ 63.7555(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section. IFG must keep copies of the COMS charts and/or electronic records, as well as all performance test information and reports. Recommend storing records off-site as well.

§ 63.7555(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you. IFG will keep COMS records, oxygen records and fuel analysis records as required.

§ 63.7555(d) *et seq.* (d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section. IFG will keep all the applicable records for the hog fuel boiler.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used. Applicable

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to §241.3(b)(1) and (2) of this chapter... Does not apply.



In accordance with § 63.7555(d)(3), A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 16 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. IFG will make the calculations as per the required equation and will keep all calculations and supporting information on file.

In accordance with § 63.7555(d)(4), a copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 17 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. IFG will make the calculations as per the required equation and will keep all calculations and supporting information on file.

(5) If, consistent with §63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year. Applicable

(6) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment. Applicable

(7) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in §63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation. Applicable

(8) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 18 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater. Not applicable. IFG choose to comply with PM not TSM.

In accordance with § 63.7555(d)(9), a copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530...IFG intends to show compliance through PM testing, not through TSM fuel analysis.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown. Applicable

(11) For each startup period, for units selecting paragraph (2) of the definition of "startup" in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels

that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged. Not applicable if not choose to rely on paragraph (2) of the definition of "startup" in §63.7575.

(12) If you choose to rely on paragraph (2) of the definition of "startup" in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (e.g., CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section. Not applicable if not choose to rely on paragraph (2) of the definition of "startup" in §63.7575.

(13) If you choose to use paragraph (2) of the definition of "startup" in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of "startup" in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below. Not applicable if not choose to rely on paragraph (2) of the definition of "startup" in §63.7575

§ 63.7555(e) If you elect to average emissions consistent with § 63.7522... IFG does not intend to use emissions averaging.

§ 63.7555(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f). IFG will keep all the applicable records if they chose to use efficiency credits from energy conservation measures.

§ 63.7555(g) If you elected to demonstrate that the unit meets the specifications for mercury for the unit designed to burn gas 1 subcategory ... Does not apply.

§ 63.7555(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel ... Does not apply.

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**§ 63.7560 In what form and how long must I keep my records?** IFG will keep the records in the format required for at least 5 years.

§ 63.7560(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

§ 63.7560(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

§ 63.7560(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

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**§ 63.7565 What parts of the General Provisions apply to me?**

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. Table 10 is included at the end of this analysis showing which General Provisions apply to IFG Chilco.

#### **§63.7575 What definitions apply to this subpart?**

Terms used in this subpart are defined in the Clean Air Act, in §63.2 (the General Provisions), and in this section as follows:

*10-day rolling average* means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

*30-day rolling average* means the arithmetic mean of the previous 720 hours of valid CO CEMS data. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent. For parameters other than CO, 30-day rolling average means either the arithmetic mean of all valid hours of data from 30 successive operating days or the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating.

*Annual capacity factor* means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

*Annual heat input* means the heat input for the 12 months preceding the compliance demonstration.

*Average annual heat input rate* means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

*Bag leak detection system* means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

*Benchmark* means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

*Biodiesel* means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see §63.14).

*Biomass or bio-based solid fuel* means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.*, trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other

bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (e.g., almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

*Blast furnace gas fuel-fired boiler or process heater* means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

*Boiler* means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

*Boiler system* means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

*Calendar year* means the period between January 1 and December 31, inclusive, for a given year.

*Clean dry biomass* means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

*Coal* means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see §63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

*Coal refuse* means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

*Commercial/institutional boiler* means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

*Common stack* means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

*Cost-effective energy conservation measure* means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

*Daily block average* means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

*Deviation.* (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

*Dioxins/furans* means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

*Distillate oil* means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see §60.14).

*Dry scrubber* means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

*Dutch oven* means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

*Efficiency credit* means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

*Electric utility steam generating unit (EGU)* means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be “capable of combusting” fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

*Electrostatic precipitator (ESP)* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.



*Energy assessment* means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

*Energy management practices* means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

*Energy management program* means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

*Energy use system* includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

*Equivalent* means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an “as received” basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

*Fabric filter* means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

*Federally enforceable* means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

*Fluidized bed boiler* means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

*Fluidized bed boiler with an integrated fluidized bed heat exchanger* means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

*Fluidized bed combustion* means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

*Fossil fuel* means natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

*Fuel cell* means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

*Fuel type* means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

*Gaseous fuel* includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

*Heat input* means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

*Heavy liquid* includes residual oil and any other liquid fuel not classified as a light liquid.

*Hourly average* means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

*Hot water heater* means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

*Hybrid suspension grate boiler* means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis as demonstrated by monthly fuel analysis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

*Industrial boiler* means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

*Light liquid* includes distillate oil, biodiesel, or vegetable oil.

*Limited-use boiler or process heater* means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable annual capacity factor of no more than 10 percent.

*Liquid fuel* includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, and vegetable oil.

*Load fraction* means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection



rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5). For boilers and process heaters that co-fire natural gas or refinery gas with a solid or liquid fuel, the load fraction is determined by the actual heat input of the solid or liquid fuel divided by heat input of the solid or liquid fuel fired during the performance test (e.g., if the performance test was conducted at 100 percent solid fuel firing, for 100 percent load firing 50 percent solid fuel and 50 percent natural gas the load fraction is 0.5).

*Major source for oil and natural gas production facilities*, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

*Metal process furnaces* are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

*Million Btu (MMBtu)* means one million British thermal units.

*Minimum activated carbon injection rate* means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum oxygen level* means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum pressure drop* means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum scrubber effluent pH* means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

*Minimum scrubber liquid flow rate* means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

*Minimum scrubber pressure drop* means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

*Minimum sorbent injection rate* means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion not using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

*Minimum total secondary electric power* means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

*Natural gas* means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see §63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure  $C_3H_8$ .

*Opacity* means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

*Operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period. For calculating rolling average emissions, an operating day does not include the hours of operation during startup or shutdown.

*Other combustor* means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

*Other gas 1 fuel* means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

*Oxygen analyzer system* means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other

appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

*Oxygen trim system* means a system of monitors that is used to maintain excess air at the desired level in a combustion device over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

*Particulate matter (PM)* means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

*Period of gas curtailment or supply interruption* means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

*Pile burner* means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

*Process heater* means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in §241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

*Pulverized coal boiler* means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

*Qualified energy assessor* means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

- (i) Boiler combustion management.
- (ii) Boiler thermal energy recovery, including
  - (A) Conventional feed water economizer,
  - (B) Conventional combustion air preheater, and

- (C) Condensing economizer.
- (iii) Boiler blowdown thermal energy recovery.
- (iv) Primary energy resource selection, including
  - (A) Fuel (primary energy source) switching, and
  - (B) Applied steam energy versus direct-fired energy versus electricity.
- (v) Insulation issues.
- (vi) Steam trap and steam leak management.
- (vi) Condensate recovery.
- (viii) Steam end-use management.
- (2) Capabilities and knowledge includes, but is not limited to:
  - (i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.
  - (ii) Familiarity with operating and maintenance practices for steam or process heating systems.
  - (iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.
  - (iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.
  - (v) Boiler-steam turbine cogeneration systems.
  - (vi) Industry specific steam end-use systems.

*Refinery gas* means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

*Regulated gas stream* means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

*Residential boiler* means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* §63.14(b)).

*Responsible official* means responsible official as defined in §70.2.

*Rolling average* means the average of all data collected during the applicable averaging period. For demonstration of compliance with a CO CEMS-based emission limit based on CO concentration a 30-day (10-day) rolling average is comprised of the average of all the hourly average concentrations over the previous 720 (240) operating hours calculated each operating day. To demonstrate compliance on a 30-day rolling average basis for parameters other than CO, you must indicate the basis of the 30-day rolling average period you are using for compliance, as discussed in §63.7545(e)(2)(iii). If you indicate the 30 operating day basis, you must calculate a new average value each operating day and shall include the measured hourly values for the preceding 30 operating days. If you select the 720 operating hours basis, you must average of all the hourly average concentrations over the previous 720 operating hours calculated each operating day.

*Secondary material* means the material as defined in §241.2 of this chapter.

*Shutdown* means the period in which cessation of operation of a boiler or process heater is initiated for any purpose. Shutdown begins when the boiler or process heater no longer supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes and/or generates electricity or when no fuel is being fed to the boiler or process heater, whichever is earlier. Shutdown ends when the boiler or process heater no longer supplies useful thermal energy (such as steam or heat) for heating, cooling, or process purposes and/or generates electricity, and no fuel is being combusted in the boiler or process heater.

*Sloped grate* means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

*Solid fossil fuel* includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

*Solid fuel* means any solid fossil fuel or biomass or bio-based solid fuel.

**Startup means:**

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when

the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

*Steam output means:*

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be the appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input (lb per MWh).

(4) For a boiler that performs multiple functions and produces steam to be used for any combination of paragraphs (1), (2), and (3) of this definition that includes electricity generation of paragraph (3) of this definition, the total energy output, in terms of MMBtu of steam output, is the sum of the energy content of steam sent directly to the process and/or used for heating ( $S_1$ ), the energy content of turbine steam sent to process plus energy in electricity according to paragraph (2) of this definition ( $S_2$ ), and the energy content of electricity generated by a electricity only turbine as paragraph (3) of this definition ( $MW_{(3)}$ ) and would be calculated using Equation 21 of this section. In the case of boilers supplying steam to one or more common heaters,  $S_1$ ,  $S_2$ , and  $MW_{(3)}$  for each boiler would be calculated based on the its (steam energy) contribution (fraction of total steam energy) to the common heater.

$$SO_M = S_1 + S_2 + (MW_{(3)} \times CF_n) \quad (\text{Eq. 21})$$

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Where:

$SO_M$  = Total steam output for multi-function boiler, MMBtu

$S_1$  = Energy content of steam sent directly to the process and/or used for heating, MMBtu

$S_2$  = Energy content of turbine steam sent to the process plus energy in electricity according to (2) above, MMBtu

$MW_{(3)}$  = Electricity generated according to paragraph (3) of this definition, MWh

$CF_n$  = Conversion factor for the appropriate subcategory for converting electricity generated according to paragraph (3) of this definition to equivalent steam energy, MMBtu/MWh

$CF_n$  for emission limits for boilers in the unit designed to burn solid fuel subcategory = 10.8

$CF_n$  PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal = 11.7

$CF_n$  PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass = 12.1

$CF_n$  for emission limits for boilers in one of the subcategories of units designed to burn liquid fuel = 11.2

$CF_n$  for emission limits for boilers in the unit designed to burn gas 2 (other) subcategory = 6.2

*Stoker* means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

*Stoker/sloped grate/other unit designed to burn kiln dried biomass* means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

*Stoker/sloped grate/other unit designed to burn wet biomass* means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

*Suspension burner* means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

*Temporary boiler* means any gaseous or liquid fuel boiler or process heater that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler or process heater is not a temporary boiler or process heater if any one of the following conditions exists:

- (1) The equipment is attached to a foundation.
- (2) The boiler or process heater or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler or process heater that replaces a temporary boiler or process heater at a location and performs the same or similar function will be included in calculating the consecutive time period.
- (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.
- (4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, process heat, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

*Total selected metals (TSM)* means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

*Traditional fuel* means the fuel as defined in §241.2 of this chapter.

*Tune-up* means adjustments made to a boiler or process heater in accordance with the procedures outlined in §63.7540(a)(10).



*Ultra low sulfur liquid fuel* means a distillate oil that has less than or equal to 15 ppm sulfur.

*Unit designed to burn biomass/bio-based solid subcategory* includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

*Unit designed to burn coal/solid fossil fuel subcategory* includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

*Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

*Unit designed to burn gas 2 (other) subcategory* includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

*Unit designed to burn heavy liquid subcategory* means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

*Unit designed to burn light liquid subcategory* means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

*Unit designed to burn liquid subcategory* includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

*Unit designed to burn liquid fuel that is a non-continental unit* means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Unit designed to burn solid fuel subcategory* means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

*Useful thermal energy* means energy (i.e., steam, hot water, or process heat) that meets the minimum operating temperature, flow, and/or pressure required by any energy use system that uses energy provided by the affected boiler or process heater.

*Vegetable oil* means oils extracted from vegetation.

*Voluntary Consensus Standards or VCS* mean technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, <http://www.astm.org>), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, <http://www.asme.org>), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, + 41 22 749 01 11, <http://www.iso.org/iso/home.htm>), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 <http://www.stadards.org.au>), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, + 44 (0)20 8996 9001, <http://www.bsigroup.com>), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, <http://www.csa.ca>), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium + 32 2 550 08 11, <http://www.cen.eu/cen>), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, + 49 211 6214-230, <http://www.vdi.eu>). The types of standards that are not considered VCS are standards developed by: The United States, e.g., California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, e.g., Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

*Waste heat boiler* means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

*Waste heat process heater* means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

*Wet scrubber* means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

*Work practice standard* means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

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[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013; 80 FR 72817, Nov. 20, 2015]

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**Tables to Subpart DDDDD**  
**Including only the items that apply to IFG Chilco**

Table 1 contains no applicable emission limits for new natural gas (gas 1) boilers.

**Table 2: Emission Limits for Existing Boilers and Process Heaters**  
**[Units with heat input capacity of 10 million Btu per hour or greater]**

If your boiler or process heater is in this subcategory	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown...	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown... <sup>(1)</sup>	Using this specified sampling volume or test run duration...
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E-02 lb per MMBtu of heat input.	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input.	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 \b\ collect a minimum of 3 dscm.
2,3,4,5,6	Do not apply.			
7. Stokers/sloped grate/others designed to burn west biomass fuel.	a. CO (or CEMS)...	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input).	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh).	Collect a minimum of 2 dscm per run.
8,9,10,11,12,13,14,15,16,17,18	Do not apply.			

(1) The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity according to § 63.7500(a)(1).

**Table 3: Work Practices Standards**

If your unit is...	You must meet the following...
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited us boiler or process heater.	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.

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If your unit is...	You must meet the following...
2. This requirement does not apply because both Chilco boilers are larger than 10 mmBtu/hr.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater. <u>This requirement applies to both the natural gas boiler and the wood-fired boiler.</u>	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units.  <u>This requirement applies to both the hog fuel boiler and to the natural gas boiler.</u>	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in §63.7575: a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup.  <u>This requirement applies to the wood-fired boiler.</u>	a. You must operate all CMS during startup. b. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, <b>clean dry biomass</b> , and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of "startup" in §63.7575, once you start firing fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of "startup" in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first

If your unit is...	You must meet the following...
	<p>feeding fuels that are not clean fuels. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e).</p> <p>d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet this work practice. You must collect monitoring data during periods of startup, as specified in §63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in §63.7555.</p>
<p>6. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during shutdown.</p> <p><u>This requirement applies to the wood-fired boiler.</u></p>	<p>You must operate all CMS during shutdown.</p> <p>While firing fuels that are not clean fuels during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, ... when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas.</p> <p>You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in §63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in §63.7555.</p>

Table 4: Operating Limits for Boilers and Process Heaters

When complying with a Table 1,2,11,12, or 13 numerical emission limit using...	You must meet these operating limits...
1,2,3,4,5. Do not apply.	
<p>4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS</p> <p><u>Applies to the IFG Chilco hog fuel boiler, which is controlled by a multiclone followed by a dry electrostatic precipitator (ESP) and no wet scrubber.</u></p>	<p>a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).</p>
5, 6. Do not apply	
<p>7. Performance testing.</p> <p><u>IFG will use performance testing to demonstrate compliance with one or more emission limits.</u></p>	<p>For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.</p>
<p>8. Oxygen analyzer system.</p> <p><u>IFG will comply with this requirement.</u></p>	<p>For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O2 analyzer system as specified in §63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a).</p>
10. Does not apply.	

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

As stated in §63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate. . .
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	<u>Does not apply because PM testing will be used as allowed for TSM compliance demonstration per comments under 40 CFR 63.7510(b)</u>	
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.



4. Mercury	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784. <sup>a</sup>
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981. <sup>a</sup>
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

<sup>a</sup>Incorporated by reference, see §63.14.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013; 80 FR 72825, Nov. 20, 2015]

Table 5 lists the performance testing requirements. IFG will need to review all source test protocols very carefully to verify that they conform to the requirements listed in Table 5.

#### **Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements**

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in §63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192, <sup>a</sup> or ASTM D7430, <sup>a</sup> or ASTM D6883, <sup>a</sup> or ASTM D2234/D2234M <sup>a</sup> (for coal) or ASTM D6323 <sup>a</sup> (for solid), or ASTM D4177 <sup>a</sup> (for liquid), or ASTM D4057 <sup>a</sup> (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B <sup>a</sup> (for solid samples), ASTM D2013/D2013M <sup>a</sup> (for coal), ASTM D5198 <sup>a</sup> (for biomass), or EPA 3050 <sup>a</sup> (for solid fuel), or EPA 821-R-01-013 <sup>a</sup> (for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 <sup>a</sup> (for coal) or ASTM E711 <sup>a</sup> (for biomass), or ASTM D5864 <sup>a</sup> for liquids and other solids, or ASTM D240 <sup>a</sup> or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173, <sup>a</sup> ASTM E871, <sup>a</sup> or ASTM D5864, <sup>a</sup> or ASTM D240, or ASTM D95 <sup>a</sup> (for liquid fuels), or ASTM D4006 <sup>a</sup> (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 <sup>a</sup> (for coal), EPA SW-846-7471B <sup>a</sup> or EPA 1631 or EPA 1631E (for solid samples), or EPA SW-846-7470A <sup>a</sup> (for liquid samples), or EPA 821-R-01-013 (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 in §63.7530.
2. HCl	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192, <sup>a</sup> or ASTM D7430, <sup>a</sup> or ASTM D6883, <sup>a</sup> or ASTM D2234/D2234M <sup>a</sup> (for coal) or ASTM D6323 <sup>a</sup> (for coal or biomass), ASTM D4177 <sup>a</sup> (for liquid fuels) or ASTM D4057 <sup>a</sup> (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B <sup>a</sup> (for solid samples), ASTM D2013/D2013M <sup>a</sup> (for coal), or ASTM D5198 <sup>a</sup> (for biomass), or EPA 3050 <sup>a</sup> or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 <sup>a</sup> (for coal) or ASTM E711 <sup>a</sup> (for biomass), ASTM D5864, ASTM D240 <sup>a</sup> or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 <sup>a</sup> or ASTM E871, <sup>a</sup> or D5864, <sup>a</sup> or ASTM D240, <sup>a</sup> or ASTM D95 <sup>a</sup> (for liquid

		fuels), or ASTM D4006 <sup>a</sup> (for liquid fuels), or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250, <sup>a</sup> ASTM D6721, <sup>a</sup> ASTM D4208 <sup>a</sup> (for coal), or EPA SW-846-5050 <sup>a</sup> or ASTM E776 <sup>a</sup> (for solid fuel), or EPA SW-846-9056 <sup>a</sup> or SW-846-9076 <sup>a</sup> (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028.
3. Mercury Fuel Specification for other gas 1 fuels	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter, or	Method 30B (M30B) at 40 CFR part 60, appendix A-8 of this chapter or ASTM D5954, <sup>a</sup> ASTM D6350, <sup>a</sup> ISO 6978-1:2003(E), <sup>a</sup> or ISO 6978-2:2003(E), <sup>a</sup> or EPA-1631 <sup>a</sup> or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784 <sup>a</sup> or equivalent.
4. TSM <u>Does not apply because PM testing will be used as allowed for TSM compliance demonstration per comments under 40 CFR 63.7510(b)</u>	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192, <sup>a</sup> or ASTM D7430, <sup>a</sup> or ASTM D6883, <sup>a</sup> or ASTM D2234/D2234M <sup>a</sup> (for coal) or ASTM D6323 <sup>a</sup> (for coal or biomass), or ASTM D4177, <sup>a</sup> (for liquid fuels) or ASTM D4057 <sup>a</sup> (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B <sup>a</sup> (for solid samples), ASTM D2013/D2013M <sup>a</sup> (for coal), ASTM D5198 <sup>a</sup> or TAPPI T266 <sup>a</sup> (for biomass), or EPA 3050 <sup>a</sup> or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 <sup>a</sup> (for coal) or ASTM E711 <sup>a</sup> (for biomass), or ASTM D5864 <sup>a</sup> for liquids and other solids, or ASTM D240 <sup>a</sup> or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 <sup>a</sup> or ASTM E871, <sup>a</sup> or D5864, or ASTM D240, <sup>a</sup> or ASTM D95 <sup>a</sup> (for liquid fuels), or ASTM D4006 <sup>a</sup> (for liquid fuels), or ASTM D4177 <sup>a</sup> (for liquid fuels) or ASTM D4057 <sup>a</sup> (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample	ASTM D3683, <sup>a</sup> or ASTM D4606, <sup>a</sup> or ASTM D6357 <sup>a</sup> or EPA 200.8 <sup>a</sup> or EPA SW-846-6020, <sup>a</sup> or EPA SW-846-6020A, <sup>a</sup> or EPA SW-846-6010C, <sup>a</sup> EPA 7060 <sup>a</sup> or EPA 7060A <sup>a</sup> (for arsenic only), or EPA SW-846-7740 <sup>a</sup> (for selenium only).

	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	For fuel mixtures use Equation 9 in §63.7530.
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<sup>a</sup>Incorporated by reference, see §63.14.

[80 FR 72825, Nov. 20, 2015]

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Table 6 lists the fuel analysis requirements. If IFG decides to demonstrate compliance through fuel analysis, they will need to follow the requirements in Table 6 for sample collection and analysis.  
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#### **Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits<sup>ab</sup>**

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

**TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS<sup>AB</sup>**

<b>If you have an applicable emission limit for . . .</b>	<b>And your operating limits are based on . . .</b>	<b>You must . . .</b>	<b>Using . . .</b>	<b>According to the following requirements</b>
1. PM, TSM, or mercury	a. Wet scrubber operating parameters	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to §63.7530(b)	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM, TSM, or mercury performance test	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers)	i. Establish a site-specific minimum total secondary electric power input according to §63.7530(b)	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric

				power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	c. Opacity <u>This applies to the hog fuel boiler.</u>	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring system during the PM performance test	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the average hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
2. HCl	a. Wet scrubber operating parameters	i. Establish site-specific minimum effluent pH and flow rate operating limits according to §63.7530(b)	(1) Data from the pH and liquid flow-rate monitors and the HCl performance test	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters	i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower

				loads, multiply your sorbent injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
	c. Alternative Maximum SO <sub>2</sub> emission rate	i. Establish a site-specific maximum SO <sub>2</sub> emission rate operating limit according to §63.7530(b)	(1) Data from SO <sub>2</sub> CEMS and the HCl performance test	(a) You must collect the SO <sub>2</sub> emissions data according to §63.7525(m) during the most recent HCl performance tests. (b) The maximum SO <sub>2</sub> emission rate is equal to the highest hourly average SO <sub>2</sub> emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to §63.7530(b)	(1) Data from the activated carbon rate monitors and mercury performance test	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction, as defined in §63.7575, to determine the required injection rate.
4. Carbon monoxide for which compliance is demonstrated by a performance test <u>This applies to the hog fuel boiler.</u>	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b)	(1) Data from the oxygen analyzer system specified in §63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established

				during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test  <u>This applies to the hog fuel boiler.</u>	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to §63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

<sup>a</sup>Operating limits must be confirmed or reestablished during performance tests.

<sup>b</sup>If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

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Table 8: Demonstrating Continuous Compliance

| If you must meet the following operating limits or work practice standards...           | You must demonstrate continuous compliance by ...                                                                                                                                                                                                                                                                                                                                                            |
|-----------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1. Opacity...<br><br><u>IFG will install and operate a COMS on the hog fuel boiler.</u> | a. Collecting the opacity monitoring system data according to §63.7525(c) and §63.7535; and<br>b. reducing the opacity monitoring data to 6-minute averages; and<br>c. Maintaining daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation. |
| 2 – 7                                                                                   | Do not apply.                                                                                                                                                                                                                                                                                                                                                                                                |



| If you must meet the following operating limits or work practice standards... | You must demonstrate continuous compliance by ...                                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
|-------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 8. Emission limits using fuel analysis<br><br><u>IFG may use this method</u>  | a. conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and<br>B. Reduce the data to 12-month rolling averages; and<br>c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.<br>d. Calculate the HCl, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in §63.7530. |
| 9. Oxygen content<br><br><u>Applies to the hog fuel boiler.</u>               | a. Continuously monitor the oxygen content using an oxygen analyzer system according to §63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in §63.7525(a)(7).<br>b. Reducing the data to 30-day rolling averages; and<br>c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.                    |
| 10. Boiler or process heater operating load.                                  | a. Collecting operating load data or steam generation data every 15 minutes.<br>b. Reducing the data to 30-day rolling averages; and<br>c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c).                                                                                                                                                             |
| 11.                                                                           | Does not apply.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |

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Table 9: Demonstrating Continuous Compliance

You must submit a(n)	The report must contain...	You must submit the report...
1. Compliance Report  <u>IFG will have to do semi-annual compliance reports for hog fuel boiler and annual for the natural gas boiler</u>	a. Information required in §63.7550(c)(10 through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in §63.7550(b).
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards for periods of startup and shutdown in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and	
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard for periods of startup and shutdown, during the reporting period, the report must contain the information in §63.7550(d); and	
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e)	

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Table 10 – Applicability of General Provisions to Subpart DDDDD, does not have specific requirements for IFG.  
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Tables 11 through 13 do not apply to IFG Chilco.